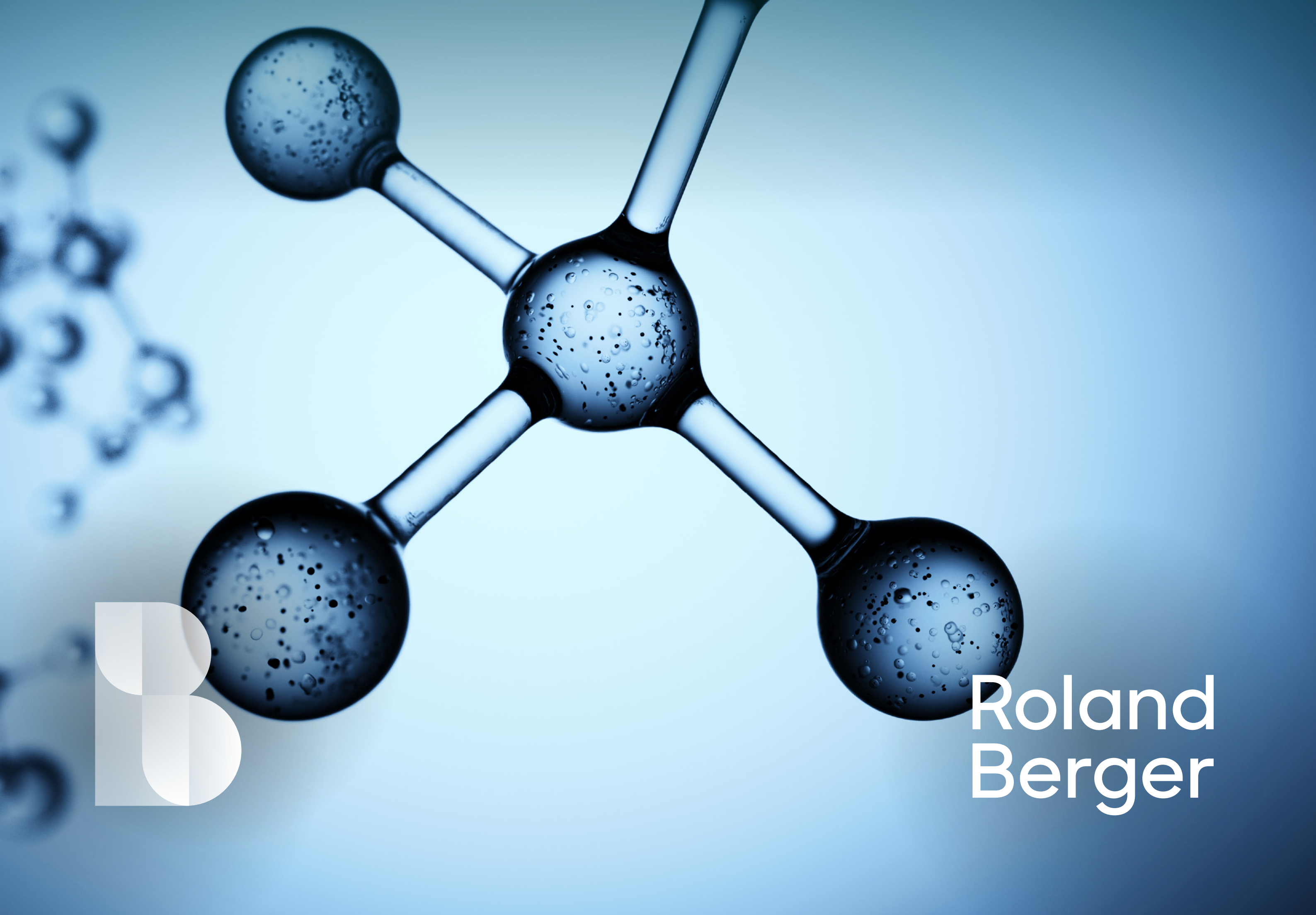
REPORT

Feasibility and potential of e-methane in the future energy mix

A comprehensive comparison of renewable energy vectors across the entire value chain in the Netherlands *van put tot pit*



Roland Berger

Foreword

The energy transition is both a necessity and an opportunity as the Netherlands strives to meet its ambitious climate goals. In this transition, exploring diverse renewable energy vectors is essential to ensuring a reliable, sustainable, and cost-effective energy system. E-methane, a renewable vector produced using renewable hydrogen and captured CO_2, is one such option that warrants careful consideration.

This report, *Feasibility and potential of e-methane in the future energy mix*, examines e-methane's potential role in the Netherlands' energy landscape, comparing it to other renewable vectors across the entire value chain *van put tot pit*. Commissioned by Gasunie and GasTerra, it has been independently prepared by Roland Berger BV ("Roland Berger") based on publicly available data, ensuring a transparent and objective assessment.

The insights in this report contribute to the ongoing dialogue on the future of energy in the Netherlands, providing relevant perspectives for policymakers, industry stakeholders, and market players. They are also applicable to other regions that share a similar reliance on natural gas and are likely to require substantial imports to meet their future renewable energy needs. A separate appendix details the assumptions and data sources used in this study.

Executive summary

Renewable energy vectors will play a critical role in the energy transition, especially in sectors that are difficult to electrify. Multiple renewable energy vectors exist, and a comprehensive comparison across the entire value chain, tailored to specific end-use cases, is essential to assess their potential and identify the most viable options for specific end-use cases. The goal of this study is to evaluate the feasibility and potential of e-methane, compared to the other renewable energy vectors biomethane, hydrogen, LOHC, ammonia and methanol, within the future energy mix of the Netherlands. The analysis includes the cost-competitiveness of these vectors across the entire value chain, from production to transportation, transmission, storage, distribution and end-use in the Netherlands. Additionally, non-financial factors such as technological maturity, environmental impact, safety characteristics and land-use efficiency are also considered.

E-methane is a renewable energy vector with a carbon neutral cycle synthesized by combining CO_2 captured from a point source or the air via DAC with renewable hydrogen. When combined with carbon capture and storage of the CO_2 released during the combustion, e-methane produced with biogenic CO_2 or DAC can even achieve negative emissions. While e-methane is expected to become more widely available and cost-competitive in long term, it will still be more expensive than CO_2 compensated natural gas and will require more cohesive regulation to scale up.

When comparing renewable energy vectors, e-methane produced from DAC has slightly higher production costs compared to ammonia and LOHC, as e-methane requires CO_2 in addition to renewable hydrogen. E-methane produced from biogenic CO_2 has lower production costs than CO_2 from DAC, but biogenic CO_2 availability is expected to be limited in the long term. In terms of transportation, pipelines are the most cost-competitive option for shorter distances, provided sufficient volumes are transported. For medium to longer distances, shipping becomes more cost-competitive. E-methane's landed cost at port is competitive with other renewable energy vectors when delivered in their end-use state. For hydrogen-specific applications, ammonia and liquid hydrogen offer the lowest landed cost.

Five key use cases where e-methane could play a role were selected for further analysis: iron and steel production, process heat for the five large industrial clusters in the Netherlands, process heat for the dispersed industrial cluster 6, central dispatchable electricity production and decentral heating. These use cases were selected based on their feasibility for e-methane and their projected demand in the Netherlands. Together, they are forecasted to represent more than 70% of the total Dutch e-methane demand. Among these, e-methane emerges as a cost-competitive vector in the long term – towards 2040 and beyond – for end-use cases with high downstream costs, specifically decentral heating, industrial process heat for cluster 6 and central dispatchable electricity production. These use cases demand extensive pipeline networks for distribution or significant seasonal storage. E-methane's cost advantage stems from its ability to serve as a "drop-in" replacement for natural gas, effectively leveraging existing natural gas infrastructure, such as transmission, seasonal storage, distribution and end-use conversion, unlike hydrogen, which requires costly modifications to the current system. E-methane's cost-competitiveness is further bolstered by its lower CAPEX intensity, the technological maturity of its downstream processes, its positive emissions impact, its safety advantages and its efficiency in land use and logistics.

Initially, e-methane could be produced using biogenic CO_2. However, due to feedstock limitations, large-scale adoption will depend on DAC for CO_2 sourcing. While DAC presents significant potential, uncertainties around its costs pose challenges for the long-term cost-competitiveness of e-methane.

Ultimately, e-methane is a promising renewable energy vector for specific use cases with high downstream costs in the Netherlands and similar regions, where established natural gas infrastructure can be leveraged for renewable energy distribution. Its efficiency in terms of capital and operational costs, emissions, safety, land use and transportation makes it a viable vector in the renewable energy mix. Given the capital-intensive nature of the energy transition, adopting e-methane conserves financial and human resources, minimizes delays and enhances societal value, enabling a more resource-efficient transition. However, to realize the full potential of e-methane, it will be essential to advance technological maturity through R&D and demonstration projects, reduce renewable hydrogen production costs and scale DAC solutions to ensure economic viability. Additionally prioritizing high-impact end-use cases and implementing supportive regulatory frameworks will be key to driving e-methane adoption and integration into the future energy mix.

Contents

The need for renewable energy vectors

Renewable energy vectors are critical to the energy transition, especially in sectors that are difficult to electrify. To identify the most viable renewable energy vectors for a net-zero future, a comprehensive comparison at the value chain level is essential. This study aims to evaluate e-methane in comparison to other renewable energy vectors across the entire value chain – from production to transportation, transmission, distribution, storage and end-use – considering both financial and non-financial factors

1

The need to address global warming and its impact has led to global initiatives to achieve net-zero greenhouse gas emissions (GHG) or climate neutrality. These plans are rooted in the recognition that human activity, particularly the burning of fossil fuels, has significantly increased the concentration of GHGs in the atmosphere and changed the Earth's climate. To mitigate their impact and limit global temperature rise, the European Union, like many other governing bodies, has set an ambitious goal to achieve climate neutrality by 2050, in line with the Paris Agreement's aim to limit the temperature increase to 1.5 °C above pre-industrial levels.

As part of the EU's net-zero strategy, the Netherlands has committed to substantial GHG emission reductions: 55% by 2030 compared to 1990 and net-zero by 2050[1]. These targets reflect a commitment to transitioning to a sustainable and resilient energy system.

In the energy transition, as much of the energy consumption as possible should be electrified while sustainable energy vectors will play a vital role in sectors where electrification is not feasible

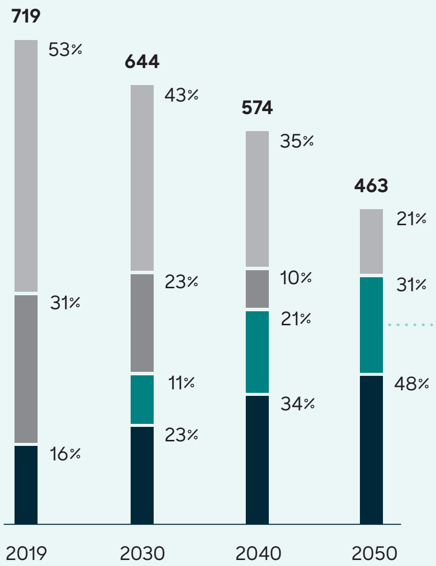
The energy transition relies on multiple levers, with electrifying as much energy consumption as possible being a key priority. Due to their higher efficiency, electric technologies reduce overall energy demand compared to fossil-based systems. For example, electric vehicles and heat pumps are more energy-efficient than conventional combustion technologies. Furthermore, GHG emissions can be minimized by powering electrification through low-emission sources such as solar, wind, geothermal, nuclear and hydropower.

In addition to electrification, energy efficiency measures - such as insulating buildings to reduce heating requirements - are crucial for further lowering energy use. While an increasing number of processes are becoming viable for electrification, it is still likely that no more than 50-60% of the Dutch final energy demand will be electrified by 2050. Sectors like heavy industry, aviation and shipping will not be fully electrified efficiently or economically before 2050. Industrial processes such as chemicals production or iron and steel manufacturing often require high-temperature process heat, which cannot be efficiently supplied by electricity. Certain fossil fuels, such as natural gas, are also used as feedstocks to produce key materials and substances, such as plastics, which require carbon atoms. Such industries and sectors need non-fossil, near-to-total net-zero alternatives if they are to decarbonize.

These so-called sustainable energy vectors such as renewable gaseous molecules (which include renewable hydrogen and its derivates and biomethane), synthetic fuels and biofuels are expected to play an increasingly vital role in replacing fossil fuels and supporting the transition to a net-zero future. The Integrated Infrastructure Outlook 2030-2050 (II3050), which forecasts future energy demand in the Netherlands for different sectors, was used as a starting point for projecting how the share of renewable energy vectors will develop in the Netherlands' future energy mix. ▶ A

1 The Dutch Climate Law

A Renewable gaseous molecules are expected to play an increasingly important role in decarbonizing non-electrifiable sectors [TWh][1)]



Sector	Main use cases
Industry	• Iron and steel production • Feedstock for refineries • Feedstock for chemicals • High-grade process heat
Mobility	• Long-haul, heavy-duty • Commercial shipping[5)] • Commercial aviation[6)]
Built environment	• Decentral heating mainly for older, less insulated buildings
Greenhouses	• Decentral heating in greenhouses

Electricity | Renewable gaseous molecules[2)] | Natural gas[3)] | Others[4)]

1) Only final energy demand is shown, meaning for example that electricity produced from renewable gaseous molecules (i.e. hydrogen and biomethane) will show as electricity demand. Demand forecasts are taken from the II3050 report, using the EU's International Ambition (IA) scenario for 2030 and the International Trading (INT) scenarios for 2040 and 2050, which are most comparable; 2) Hydrogen (derivatives) and biomethane; 3) Includes imported natural gas; 4) Includes other energy sources such as heat and oil which could also be (partially) delivered by sustainable energy vectors; 5) Excludes international shipping; 6) Excludes international aviation

Source: II3050

Sustainable energy vectors will likely form a significant part of the imports needed to meet the Dutch energy demand

The Netherlands has traditionally relied on domestic natural gas, largely from the Groningen gas field[2]. However, with the decline of natural gas production, imports have increased in recent years. To meet GHG reduction targets, the Netherlands aims to boost domestic renewable energy production, primarily from solar and wind. According to the II3050 report, the Netherlands will have around 120 GW in renewable electricity production capacity by 2040: 70 GW from solar PV, 35 GW from offshore wind and 15 GW from onshore wind. In addition, electrolysis capacity for hydrogen production is forecasted at 15 GW[3]. But even if these forecasts are realized, it will not meet total energy demand in 2040.

Energy imports will therefore be necessary. Most of these imports are expected to come in the form of sustainable energy vectors from regions that are expected to produce a surplus of energy such as the Middle East and North Africa (MENA), the US and southern and northern Europe.

2 2030-2050 Integrated Infrastructure Outlook, Netbeheer Nederland, 2023

3 Based on the International Trading (INT) scenario

Sustainable energy vectors can be classified into low-carbon and renewable vectors. This study focuses specifically on renewable energy vectors

Sustainable energy vectors can be categorized into low-carbon vectors, derived from fossil sources with carbon mitigating technologies such as carbon capture, and renewable vectors, derived from renewable energy[4] sources such as solar, wind or biomass. For example, blue hydrogen is a low-carbon vector, which can be produced through autothermal reforming of natural gas combined with carbon capture and storage (CCS). These sustainable energy vectors will not only supply energy for sectors that cannot be electrified but also serve as renewable feedstocks for certain industrial processes, such as refining and chemicals production.

Low-carbon vectors are likely to play a key role in the short to medium term due to their cost-competitiveness compared to renewable energy vectors. However, the focus of this study is on renewable energy vectors, as they are expected to be critical in reducing dependency on finite fossil resources and achieving net-zero emissions in the long term.

4 For the purposes of this study, within renewable energy, renewable electricity is defined as electricity generated from solar, wind, hydropower, geothermal or nuclear systems. Although nuclear energy is not classified as renewable in the EU, its carbon emissions are very low. Nuclear can thus be used for production of renewable energy vectors if the average emission intensity of the electricity grid is <18 g CO_2e/MJ

DEEP DIVE

Renewable energy vectors can be distinguished based on whether their origin was organic or synthetic. ▶ B

Organic renewable energy vectors are derived from organic matter, such as plants or animal waste, which mainly consists of carbon and hydrogen atoms. These carbon atoms come from atmospheric carbon dioxide (CO_2) absorbed by plants and converted into organic matter. From this matter, gaseous vectors like biomethane (CH_4) and liquid vectors like biomethanol (CH_3OH) can be produced.

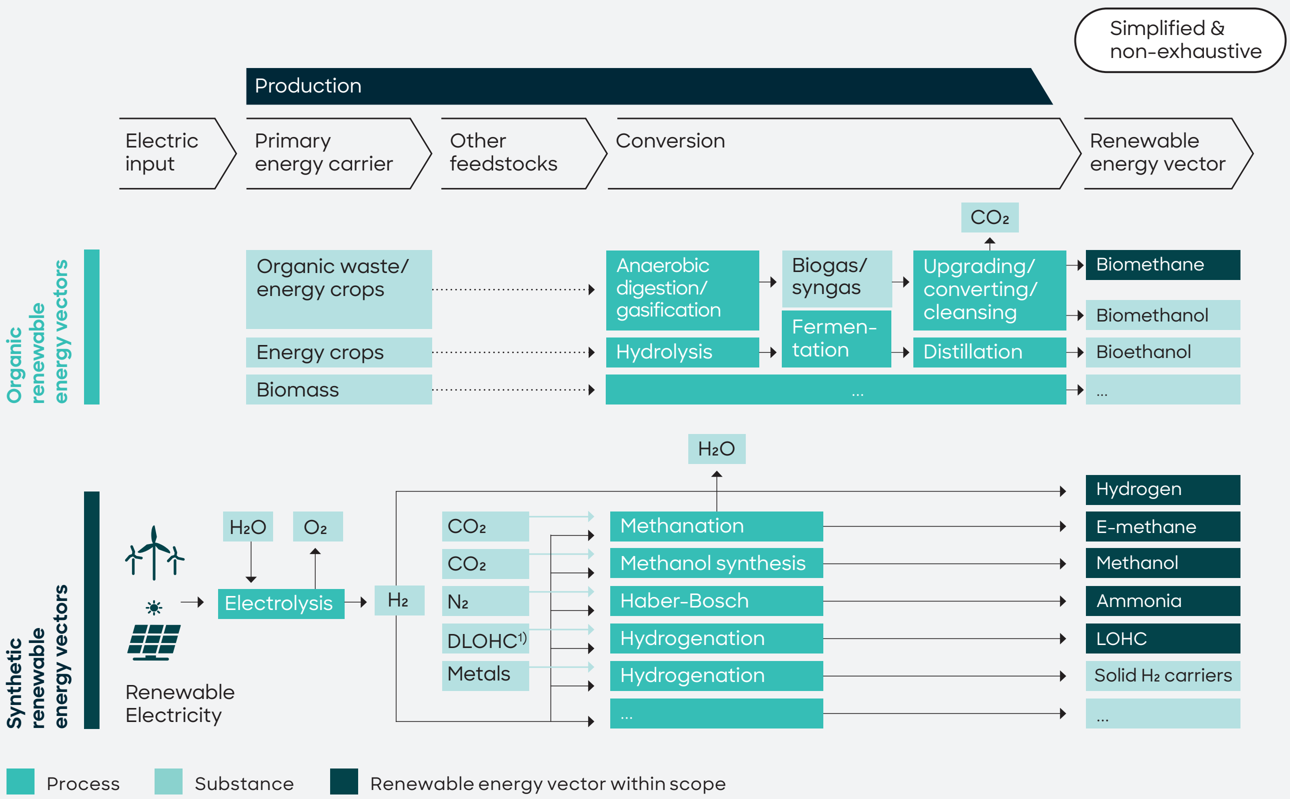
When organic renewable energy vectors are combusted, CO_2 is released back into the atmosphere. This CO_2 is considered part of the short carbon cycle, having been recently absorbed by organisms, and is thus considered net-zero emissions. In contrast, combusting fossil fuels releases CO_2 from the long carbon cycle: that CO_2 was absorbed from the atmosphere millions of years ago, and its release contributes to current atmospheric buildup of CO_2.

Synthetic energy vectors are chemically produced, starting with renewable electricity. This electricity can split water into hydrogen and oxygen via electrolysis to produce renewable hydrogen, which can either be used directly or converted into other synthetic renewable energy vectors to increase energy density and facilitate transportation or meet specific end-use requirements.

Examples of such hydrogen carriers include liquid organic hydrogen carriers (LOHC), ammonia (NH_3) and methanol (CH_3OH). LOHC can absorb and release hydrogen, making it transportable like oil. Ammonia, produced from hydrogen and nitrogen via the Haber-Bosch process, liquefies at -33 °C, making it easier to transport than in gaseous form. After transport, ammonia can be potentially reconverted into hydrogen by ammonia cracking or can be directly used as feedstock for fertilizers or fuel for applications such as shipping and electricity. Methanol, produced either organically or synthetically, can also be transported as a liquid (under room temperatures) and later reconverted to hydrogen or used directly as chemical feedstock or fuel for applications such as shipping. Hydrogen can also be converted into solid hydrogen carriers such as sodium boron hydride, iron hydride and magnesium hydride. These solid hydrogen carriers are being further explored in initiatives such as the Iron Power alliance. However, this and other solid hydrogen carriers are considered out of scope for the purpose of this study due to the relatively lower technological maturity compared to other hydrogen carriers.

Like methanol, renewable methane (CH_4) can be produced either organically or synthetically. Methane from an organic source is called biomethane, while synthetic methane is also known as e-methane. E-methane is produced through methanation of hydrogen produced through electrolysis and CO_2. The notable aspect of renewable methane is that it is chemically close to natural gas, allowing the use of existing natural gas infrastructure and equipment for its transportation, storage and end-use. Additionally, renewable methane can be reconverted back to hydrogen if needed.

B Organic renewable energy vectors are produced from biomass, whereas synthetic renewable energy vectors are produced from renewable hydrogen



1) Dehydrogenated liquid organic hydrogen carrier

Source: European commission, Desk research

Within renewable energy vectors, this study takes a close look at e-methane and compares it to renewable hydrogen (derivatives) from beginning to end of the value chain considering both financial and non-financial factors

Over the years, numerous studies – e.g. from leading organizations International Energy Agency (IEA) and International Renewable Energy Agency (IRENA) – have compared renewable hydrogen and its derivatives, focusing primarily on the initial stages of the value chain: from production to long-distance transportation and reconversion. The costs and challenges in the latter stages of the value chain, including storage, distribution and end-use conversion, are rarely considered. Yet local investments in these downstream stages will be essential to ensure the scalability and viability of renewable energy vectors. They are not just operationally significant, they will drive the overall cost-effectiveness, reliability and integration of the vectors into the economy.

Moreover, most existing studies tend to focus on a single aspect of comparison, such as financial metrics, GHG emissions intensity, or technological maturity. While these analyses are valuable, they do not offer the integrated perspective necessary for informed decision-making. Thus, a comprehensive comparison of energy vectors across the entire value chain *(van put tot pit)* is required.

This study seeks to address these gaps by evaluating both the financial and non-financial feasibility of e-methane and comparing it to renewable hydrogen and its derivatives from beginning to end of the value chain. Despite its potential advantages in the latter value chain stages of transportation, storage and end-use conversion, e-methane has rarely been the subject of renewable energy vector studies. Only recently have Agora[5] and Frontier[6] compared e-methane with renewable hydrogen and its derivatives, but these studies focused only on the initial value chain steps. A recently published multi-criteria analysis (MCA)[7] of hydrogen carriers in the Netherlands does include e-methane for comparison throughout the value chain but provides only a high-level cost estimate that is largely based on the HyDelta report[8].

This comprehensive assessment of e-methane and other vectors thus incorporates financial factors, GHG emissions, technology readiness levels (TRL) and safety considerations, and does so across the entire value chain. By examining all these dimensions, this study offers a nuanced evaluation that will enable stakeholders to identify the most suitable renewable energy carrier for specific situations.

It is important to note that multiple renewable energy vectors likely will coexist in the future. However, each vector requires local infrastructure, ranging from import and storage facilities to transportation networks and end-use conversion equipment. Given the investment costs and spatial requirements, developing full infrastructure for each renewable energy vector

5 Hydrogen import options for Germany, 2023
6 Comparative analysis of import costs of synthetic methane to Germany, 2024
7 Comparison of hydrogen carriers – Multi-criteria analysis of supply chains in the Netherlands, 2024
8 Value Chain Analysis – Hydrogen value chain literature review, 2021; Risks, uncertainty and collaboration in the hydrogen-based value chain – Technical analysis of hydrogen supply chains, 2023

likely is uneconomical and given the required man-power likely is unfeasible. Consequently, choices must be made based on use cases of the vectors in all aspects of the value chain.

The goal of this study is to evaluate the feasibility and potential of e-methane within the future energy mix of the Netherlands

This study aims to investigate the potential of e-methane alongside other renewable energy vectors biomethane, hydrogen, LOHC, ammonia and methanol. Using 2040 as the reference year, this study therefore provides a long-term perspective, extending towards 2040 and beyond, on the future energy mix in the Netherlands in terms of:

- Demand for renewable energy vectors through the lens of various use cases in the Netherlands
- The cost-competitiveness[9] of renewable energy vectors across the entire value chain
- Additional factors such as technological maturity, environmental impact, safety characteristics and land-use efficiency

The study is structured as follows: Chapter 2 introduces the e-methane energy vector and the status of its development. Chapter 3 identifies the key use cases that are potentially attractive for e-methane. Chapter 4 outlines the boundary conditions and key input assumptions used in the study. Chapter 5 compares the cost of e-methane to other energy vectors for identified use cases. Chapter 6 evaluates the energy vectors on non-financial parameters such as emissions, safety and land use. Chapter 7 presents the conclusions and recommendations of the study.

9 Cost-competitiveness only includes actual costs and excludes government subsidies or other financial schemes

DEEP DIVE

A typical value chain for renewable energy vectors imported into the Netherlands begins with production. This involves producing the primary energy carrier, such as biomass or renewable hydrogen, and converting it into the renewable energy vector. ▶ C

The next step is long-distance transportation, where the renewable energy vector is first prepared for transportation – either compressed for pipelines or liquefied for vessels – and then transported. Shipping also includes storage at both the production and import locations, followed by gasification at the import location if the vector was liquefied.

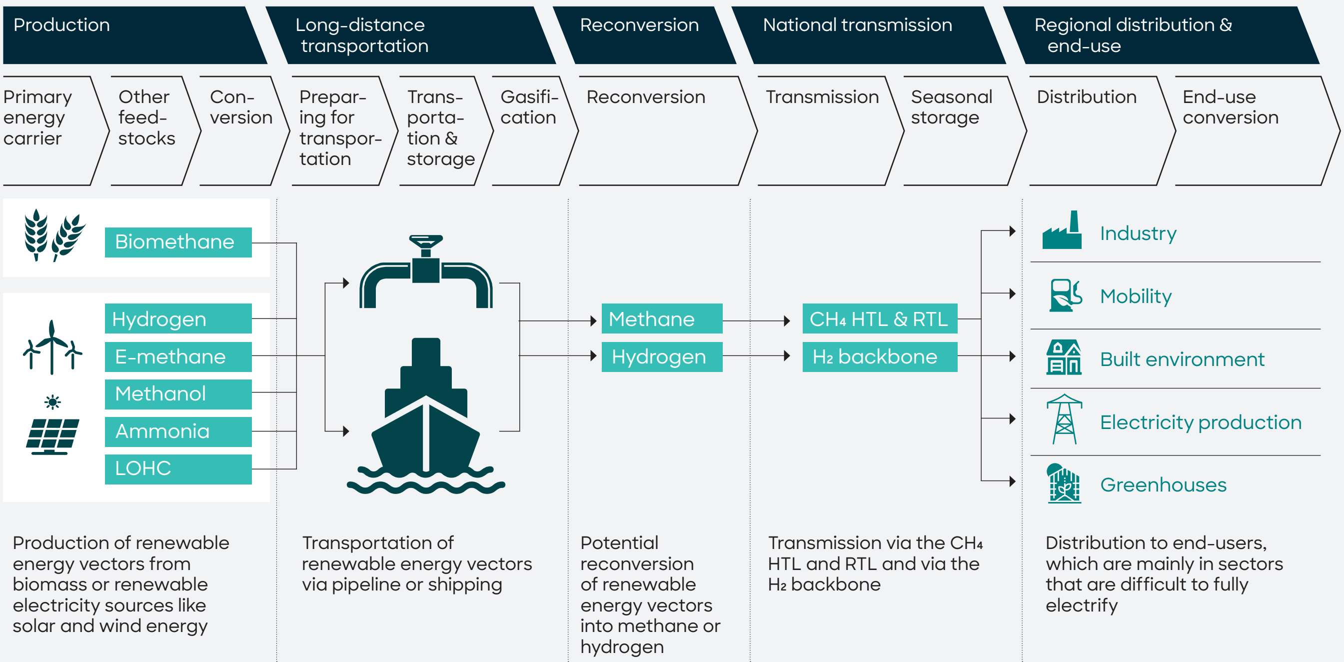
The third step involves the potential reconversion of the renewable energy vector into hydrogen, depending on the end-use. For instance, oil refining requires hydrogen, necessitating reconversion. Conversely, in fertilizer production, ammonia is needed, so reconversion is unnecessary if the renewable energy vector is ammonia.

After potential reconversion, the renewable energy vector enters the national transmission network, which may include seasonal storage. The Netherlands has an extensive transmission and storage network for methane, which includes main (HTL) and regional (RTL) transmission pipelines. There are also plans to develop a hydrogen backbone by 2030[10], including sufficient storage capacity to operate the system. This would require repurposing part of the existing HTL and RTL from methane to hydrogen, including the necessary adjustments. The transmission methods for other vectors like ammonia and methanol are still being determined.

10 Hynetwork roll-out plan (https://www.hynetwork.nl/en/about-hynetwork/the-roll-out-plan)

Finally, the renewable energy vectors are distributed to end-users. The final step varies greatly depending on the use case. While for e-methane, most existing end-use equipment for natural gas can likely be used as-is, additional investments are likely required to adapt the equipment to be suitable for other energy vectors like hydrogen.

C The value chain for renewable energy vectors includes production, transportation, reconversion, national transmission, regional distribution and end-use



E-methane, potentially attractive renewable energy vector

E-methane is a renewable energy vector which can serve as a "drop-in" vector, leveraging the existing natural gas infrastructure and thus minimizing transition costs. When produced using biogenic CO_2 or DAC and combined with CCS at end-use, it will enable negative emissions. While e-methane is expected to become more widely available and cost-competitive in the future, it will still be more expensive than CO_2 compensated natural gas and will require more cohesive regulation to scale up

2

The Netherlands' transition to net zero involves substantial changes in the energy mix. Natural gas, which comprises about one-third of the country's energy supply[11], primarily consists of methane (85-90%) alongside smaller quantities of hydrocarbons like ethane and propane, as well as traces of non-hydrocarbon gases such as CO_2 and nitrogen. The exact makeup of natural gas can vary depending on its source, including conventional reservoirs, shale formations or coal seams.

E-methane can serve as a "drop-in" vector, leveraging the existing natural gas infrastructure and thus minimizing transition costs

An option for decarbonizing the Dutch energy supply is e-methane, a renewable gas created by combining renewable hydrogen with GHG-neutral CO_2. E-methane can be synthesized to meet the specific compositions of L-gas and H-gas[12] utilized in the Netherlands, making it nearly identical to natural gas in terms of combustion properties, calorific value and behavior within pipeline systems. This alignment enables e-methane to serve as a "drop-in" replacement, effectively leveraging the existing natural gas infrastructure – such as LNG terminals, vessels, storage facilities, pipelines and end-use equipment. By doing so, it has the potential to minimize additional downstream investments needed during the energy transition. While e-methane's production costs will be higher than hydrogen due to the additional conversion step, its ability to minimize infrastructure changes may offset these costs. This allows for a less disruptive and therefore possibly less costly shift from fossil fuels to renewable energy vectors – while still meeting the aims of the Paris Agreement.

E-methane is a renewable energy vector with a carbon neutral cycle, as the CO_2 emitted during combustion equals the CO_2 captured during its production

E-methane is synthesized by combining CO_2 captured from biogenic point sources or from the air via direct air capture (DAC) with renewable hydrogen produced via electrolysis[13]. When combusted, e-methane releases the same amount of CO_2 which was previously captured during its production – thus effectively resulting in a carbon neutral cycle with no net increase in CO_2 emissions to the atmosphere. In combination with CCS of the CO_2 released during combustion, even negative emissions can be achieved. E-methane can also be created with CO_2 captured from the combustion of fossil fuels. In this case, the fossil source from which the CO_2 is captured is considered the CO_2 emitter.

The Sabatier method remains the only commercialized synthesis method for e-methane – for now

E-methane can be produced via several methods, including Sabatier methanation, hybrid methanation, direct methanation and biological methanation. Currently, the Sabatier pro-

11 IEA

12 L-gas refers to low-calorific gas (from the Groningen gas field) and H-gas refers to high-calorific gas (from most other places in the world)

13 The RED II Delegated Act restricts the eligibility of CO_2 captured from industrial activities until 2041 (or 2036 for CO_2 from electricity production) for RFNBO, meaning that only CO_2 captured through DAC or from biogenic sources can be used for e-methane production after 2040 if used as RFNBO

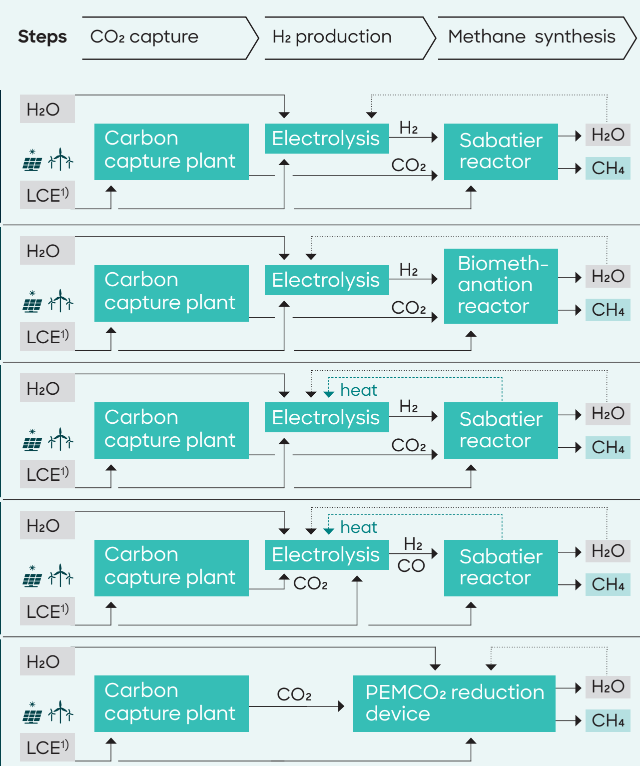
cess is the only commercially viable method. It involves a chemical reaction between hydrogen and CO_2 over a nickel catalyst at 200-500 °C, achieving an overall process efficiency of both electrolysis and methanation of about 65%. ▶ D

Emerging technologies such as biological methanation leverage microorganisms to catalyze the reaction between hydrogen and CO_2 at low temperatures, achieving efficiencies of up to 65%. Hybrid methods improve efficiency by utilizing heat from the exothermic reaction to support hydrogen production. Examples include conventional Sabatier methanation integrated with hydrogen electrolysis and solid oxide electrolyzer cell (SOEC) methanation. In SOEC methanation, water and CO_2 are co-electrolyzed to produce hydrogen and carbon monoxide (CO), which are subsequently converted to methane, potentially achieving efficiencies of up to 90%. Direct methanation combines water electrolysis and CO_2 reduction in a single step using proton-exchange membrane (PEM) electrolysis, achieving efficiencies of up to 80%. These emerging methods represent promising advancements in the efficiency and scalability of e-methane production in the future.

D There are five main methods to synthesize e-methane, but Sabatier is the only commercialized method

Simplified & non-exhaustive

Process flow



Key parameters

Category	Technology	Reaction method	Methanation temp. [°C]	Overall process efficiency2) [%]	Technological maturity
Commercial	Conventional Sabatier methanation	Chemical	200-500	60-65	High
Innovative	Biological methanation	Biochemical	35-65	60-65	Medium
Innovative – Hybrid methods	Sabatier methanation	Electro-chemical	220	70-80	Medium
Innovative – Hybrid methods	SOEC methanation	Electro-chemical	800	75-90	Low
Innovative	$PEMCO_2$ methanation	Electro-chemical	60-80	70-80	Low

1) Low carbon energy; 2) Figure comprises efficiency of electrolysis and methane synthesis

Source: Japan Gas Association, IEA, Store & Go, DENA

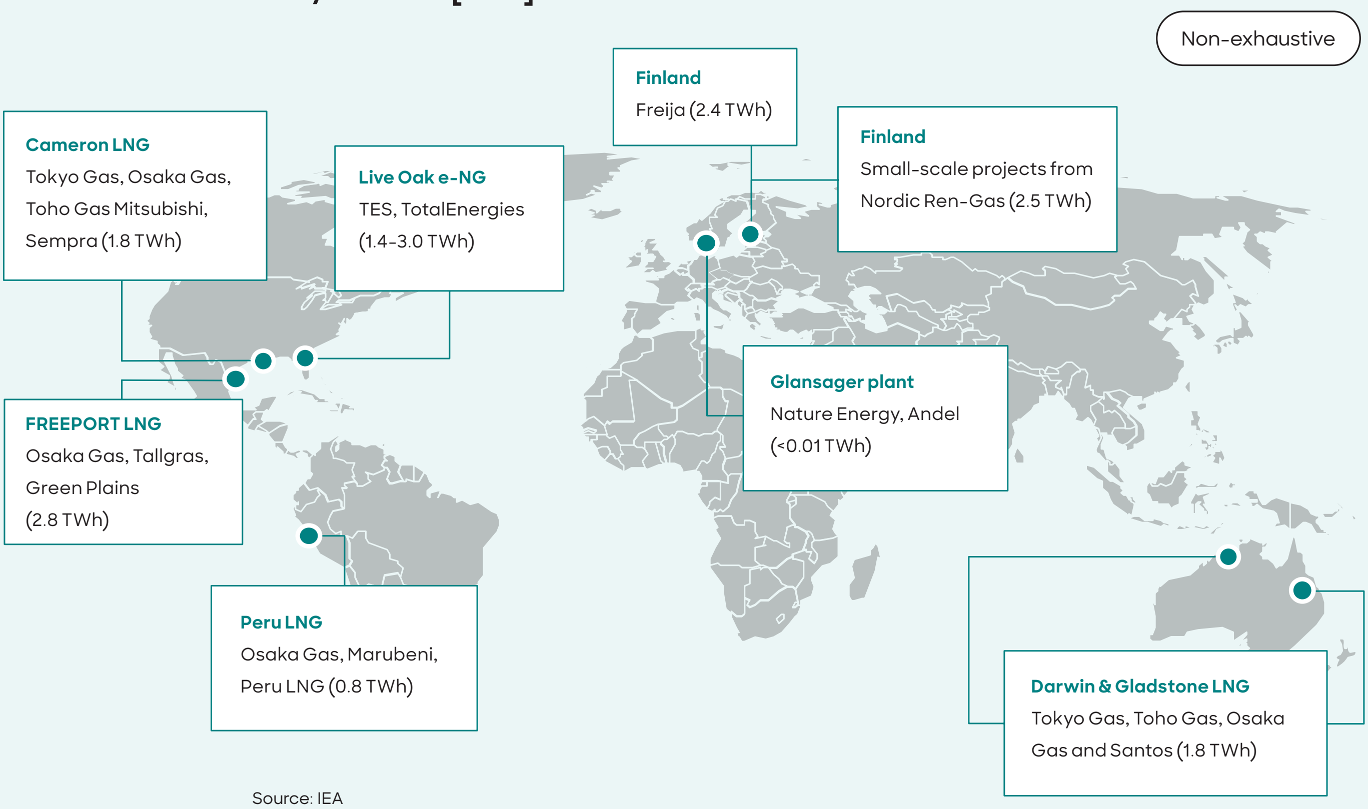
Despite the potential of these newer methods to improve efficiency, they are not yet commercially available, making Sabatier methanation the most viable production method for e-methane today. It is therefore the reference production method in this study.

E-methane is gaining momentum, with global production expected to exceed 10 TWh by 2030

The IEA projects global e-methane production could exceed 10 TWh by 2030[14], contingent on securing investments in ongoing projects. ▶ E These projects are in regions with abundant and low-priced renewable electricity, primarily the US, Australia and the Nordics, with over 50% of supply expected from the US. Japan positions itself as a leader in e-methane development, aiming to source 1% of city gas from e-methane by 2030 and 90% by 2050, with major investments in large-scale production abroad, including in Cameroon and the US. In Europe, TES is planning to build an e-methane import hub in Germany[15], while Ren-Gas leads small-scale projects in Finland targeting 2.5 TWh. The sector is also gaining momentum with the formation of the global e-NG[16] coalition, which includes several industry leaders[17].

14 E-methane - a new gas for a net-zero future, IEA
15 TES is planning to build an LNG import terminal in Germany with the aim to later import e-methane produced in US
16 E-natural gas is synonymous with e-methane
17 https://www.eng-coalition.org/

E Global e-methane production could potentially exceed 10 TWh by the year 2030 [TWh]

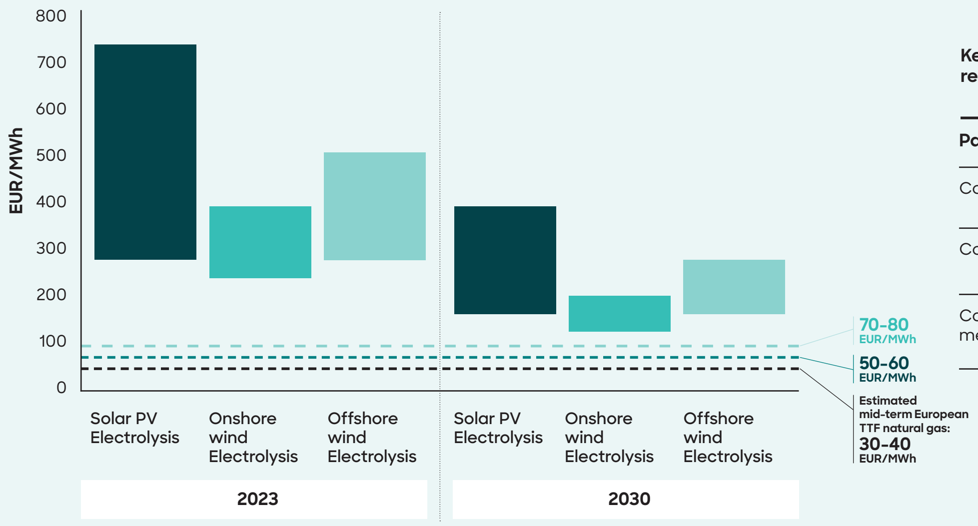


Source: IEA

E-methane production costs are expected to drop by 2030, though not below the cost of natural gas

Based on IEA calculations, current e-methane production costs are in the range of 250-700 EUR/MWh. This is largely driven by the cost of renewable hydrogen and the GHG-neutral CO_2. By 2030, e-methane production costs are expected to drop to 150-300 EUR/MWh due to reductions in the costs of renewable hydrogen and carbon capture, improved methanation efficiency and economies of scale. ▶ **F** However, even at these lower costs e-methane production costs remain several times that of natural gas, which is expected to be priced at EUR 50-80 EUR/MWh, including the ETS price.

F According to IEA, current e-methane costs are in the range of 250 - 700 EUR/MWh (3-12 x NG prices including ETS) - Costs projected to decrease by 2x by 2030 [EUR/MWh]



Key cost reduction drivers		Impact on production cost
Parameter	**Trend**	
Cost of H_2	↘	High
Cost of DAC	↓	Medium
Cost of methanation	↘	Low

- - - NG price assuming an ETS price of EUR 100 per ton CO_2 emitted
– – NG price assuming an ETS price of EUR 200 per ton CO_2 emitted
↑ Costs strongly increasing
↗ Costs increasing
↘ Costs decreasing
↓ Costs strongly decreasing

Source: IEA, Desk research

E-methane is expected to meet renewable fuel regulations globally, but a more cohesive regulatory framework is essential for its scale-up

E-methane is expected to meet the regulatory requirements for renewable fuel in key regions such as the US, EU and Japan. For example, e-methane can be classified as a renewable fuel of non-biological origin (RFNBO) under the EU's Renewable Energy Directive (RED) II.

However, the regulatory framework for e-methane is still in the early stages of development. While existing policies like the EU Green Deal indirectly support the transition to e-methane, they do not explicitly identify e-methane as a primary energy vector for decarbonization.

That being said, the source of CO_2 used in methane synthesis is increasingly scrutinized in global legislation. The International Organization for Standardization (ISO) has established international standards for calculating the carbon footprint of e-methane, allowing CO_2 from air, biogenic sources, or a company's own operations to be considered eligible. Japan's Clean Gas Certificate scheme allows the use of CO_2 for e-methane as long as it does not contribute to an increase in atmospheric CO_2 levels upon combustion, though it does not specify the exact eligible CO_2 sources. In the EU, the RED II Delegated Act restricts the eligibility of CO_2 captured from industrial activities until 2041 (or 2036 for CO_2 from electricity production), meaning that only CO_2 captured through DAC or from biogenic sources can be used for e-methane production after 2040. In line with these EU regulations, this study considers only CO_2 captured from biogenic sources or via DAC for e-methane production, as well as for methanol production which is produced via renewable hydrogen and captured carbon.

While e-methane is contributing to carbon reduction targets today, the regulatory environment remains fragmented and in development. For large-scale deployment, enhanced and more cohesive regulations will be essential to scale up e-methane production.

End-use cases key in determining viability of renewable energy vector

By 2040, the Netherlands' projected demand for renewable energy vectors will be 137 TWh. Five key use cases are particularly promising for e-methane adoption based on feasibility and projected demand of e-methane. For each use case, considerations in different parts of value chain have been defined for both e-methane and hydrogen

3

Evaluating the feasibility and potential of e-methane in comparison with other renewable energy vectors requires analyzing a number of end-use cases in which demand for renewable gaseous molecules is significant and e-methane is a feasible option to meet that demand.

Projected demand in 2040 for renewable gaseous molecules is 137 TWh

E-methane and other renewable energy vectors are expected to be crucial for decarbonizing sectors that are difficult to electrify fully, such as industry, dispatchable electricity production, the built environment and greenhouses. Key sectors like fertilizers and refineries will also rely on these renewable energy vectors as feedstock. The future demand for renewable molecules will depend on factors like industrialization trends, electrification progress and grid capacity. To estimate the projected demand in the Netherlands, the II3050 report has been used as a reference for this study.

This study uses the international trading (INT) scenario as the reference case for projecting energy demand in the Netherlands[18]. The INT scenario assumes an important role for international supply chains and global trading of renewable energy vectors. The choice for this scenario was driven by the belief that coordinated global efforts are essential for achieving climate neutrality, given the shared nature of the climate crisis. The choice of scenario influences the cost of transporting renewable energy vectors in the Netherlands, as the costs directly depend on the total transported volume. The higher the volume the lower the cost per transported MWh. The study will also determine the sensitivity of other scenarios to transportation costs.

The II3050 report does not explicitly mention or forecast future e-methane demand. As e-methane has similar use cases to both hydrogen and biomethane, this study considers the total hydrogen and biomethane demand as the total addressable market for e-methane (and other renewable energy vectors). For the purpose of this study, renewable hydrogen and renewable methane (i.e. biomethane and e-methane) are collectively referred to as renewable gaseous molecules.

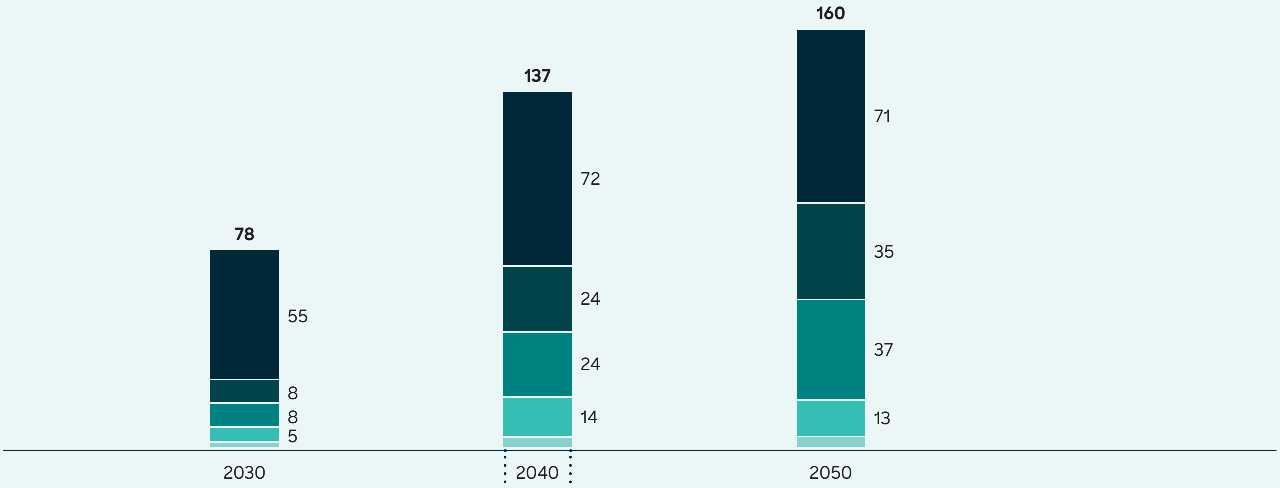
The total projected demand for renewable gaseous molecules in the Netherlands in 2040, according to the INT scenario, is 137 TWh[19,20]. The largest share of this demand (72 TWh) is expected from industry, followed by mobility, the built environment, electricity production and greenhouses. ▶ G

18 The II3050 report outlines four scenarios for the future energy transition, varying in the degree of government control versus market-driven developments. Moreover, the scenarios differ in the scale of the transition – whether national, regional or international – and consider the varying technology and energy carrier choices made by different sectors. The four scenarios are decentral initiatives (DEC), national leadership (NAT), European integration (EUR) and international trading (INT). For further details on the II3050 report, please refer to the appendix

19 In each use case, demand refers to domestic demand in the Netherlands and does not account for international demand. For example, the demand for renewable gaseous molecules in shipping is based solely on domestic requirements and does not include fuel bunkering for international shipping

20 Figure A shows the final energy demand for renewable gaseous molecules in 2040, which is 121 TWh. That number does not include renewable gaseous molecule demand for electricity production and district heating, which is included in the 137 TWh given here

G Demand for renewable gaseous molecules is expected to be driven primarily by the industrial, mobility and built environment sectors [TWh]



Sector		Use case	Demand [TWh]	Description
Direct industry	Energetic	**Process heat** for clusters 1-5[1]	**21**	Renewable gaseous molecules used for moderate and high-temperature heat for industrial processes across different industries[3]
		Process heat for cluster 6[2]	**10**	
	Non-energetic	**Iron and steel**	**14**	Methane or hydrogen used for moderate and high-temperature heat and as feedstock for steel production
		Refineries	**18**	Hydrogen used as feedstock for hydrocracking and desulfurization to produce petroleum products
		Ammonia end-products	**4**	Hydrogen or ammonia used as feedstock to produce ammonia end-products in the chemicals industry
		Methanol end-products	**2**	Hydrogen or methanol used as feedstock to produce methanol end-products in the chemicals industry
		Other end-products	**2**	Methane and/or hydrogen used as feedstock to produce several other end-products in the chemicals industry
Mobility		**Heavy duty**	**14**	Renewable gaseous molecules used as fuel for trucks and buses
		Light duty	**9**	Renewable gaseous molecules used as fuel for cars and vans
		Shipping[4]	**1**	Renewable gaseous molecules used as fuel for inland shipping
		Rail	**0.1**	Renewable gaseous molecules used as fuel for freight and passenger trains
		Aviation[5]	**0.04**	Renewable gaseous molecules used as fuel for domestic (cargo) flights
Built environment		**Decentral heating**	**23**	Renewable gaseous molecules used for decentral heating and other energy use of residential and utility buildings
		District heating	**1**	Renewable gaseous molecules used for heating water, which is centrally distributed to residential and utility buildings
Electricity		**Central**	**14**	Renewable gaseous molecules used for centralized power plants for flexible electricity generation
		Decentral	**0**[6]	Renewable gaseous molecules used for decentralized power plants for electricity generation for local use
Greenhouses		**Greenhouses**	**3**	Renewable gaseous molecules used for decentral heating of greenhouses for agriculture

1) Includes refineries and ammonia, methanol and other end-products; 2) Includes the food and beverage industry, paper industry and other industries; 3) Excludes demand for high-temperature heat for iron and steel production; 4) Excludes ~60 TWh forecasted demand for international bunkering of synthetic and biofuels in the Netherlands, based on IRENA report on decarbonizing the shipping sector, which estimates 3.5 EJ of 8.5 EJ total global shipping demand in 2040 to be for synthetic and biofuels and 6% of global bunkering to be in the Netherlands; 5) Excludes ~20 TWh forecasted demand for synthetic aviation fuel (SAF) for international aviation in the Netherlands in 2050, based on INT scenario in II3050 report; 6) Not evaluated as it is expected to have little demand for renewable gaseous molecules

Source: II3050

H Iron and steel, process heat, decentral heating and central dispatchable electricity production are shortlisted as main use cases for e-methane to further deepdive [TWh] 1), 2)

Sector		Use case	2040	2050	E-methane	Hydrogen[8]	Ammonia	Methanol	Shortlisted
Direct industry	Energetic	Process heat for clusters 1–5[3]	21	29	✔	✔	✓	~	✔
		Process heat for cluster 6[4]	10	10	✔	✔	✓	~	✔
	Non-energetic	Iron and steel	14	3 INT assumes HBI[9] will be imported	✔	✔	✗	✗	✔
		Refineries	18	14	~	✔	✗	✗	
		Ammonia end-products	4	14	~	✔	✔	✗	
		Methanol end-products	2	1	~	✔	✗	✔	
		Other end-products	2	1	✔	✔	✗	✗	
Mobility		Heavy duty	14	20	✔	~	✗	✔	
		Light duty	9	12	✔	~	✗	✔	
		Shipping[5]	1	4	✔	✓	✓	✔	
		Rail	0	0	✗	✓	✗	✗	
		Aviation[6]	0	0	✗	✗	✗	✗	
Built environment		Decentral heating	23	33	✔	✔	✗	✗	✔
		District heating	1	4	✔	✔	✗	✗	
Electricity		Central	14	13	✔	✔	✓	~	✔
		Decentral	Not evaluated as it is expected to have low demand for renewable gaseous molecules						
Greenhouses		Greenhouses[7]	3 9 3–12	4 5 4–8	✔	✔	✗	✗	
		Total	137 9 146	160 5 164					

Considered as a feasible option: ✔ Not considered: ✓ Likely not a feasible option for NL ~ Likely not economically viable ✗ Not technologically proven or low maturity, feasible only for niche applications

1) Figure details the applicability of the renewable energy vectors as a final energy form for the end use case. For example, hydrogen for process heat can be delivered as hydrogen or via ammonia or other liquid hydrogen carriers; 2) For further details on applicability of energy vectors per use case, please refer to the appendix document; 3) Includes refineries and ammonia, methanol and other end-products; 4) Includes the food and beverage industry, paper industry and other industries; 5) Excludes ~60 TWh forecasted demand for international bunkering of synthetic and biofuels in the Netherlands, based on IRENA report on decarbonizing the shipping sector, which estimates 3.5 EJ of 8.5 EJ total global shipping demand in 2040 to be for synthetic and biofuels and 6% of global bunkering to be in the Netherlands; 6) Excludes ~20 TWh forecasted demand for synthetic aviation fuel (SAF) for international aviation in the Netherlands in 2050, based on INT scenario in II3050 report; 7) Light green bar represents demand from district heating, potentially to be served by renewable gaseous molecules; 8) Hydrogen as a molecule for end-use, also includes other molecules as hydrogen carriers; 9) Hot briquetted iron

Source: II3050, Desk research

In industry, renewable gaseous molecules can provide moderate to high-temperature process heat, which is difficult to electrify. They are also needed as essential feedstock for chemical processes, enabling the production of key materials and reducing reliance on fossil inputs.

In mobility, demand is primarily driven by heavy-duty transportation, while in the built environment, it is driven by (hybrid) decentral heating for residential and utility buildings. In electricity production, renewable gaseous molecules will play a role in dispatchable power production to balance the intermittency of renewable energy sources like wind and solar, which are forecasted to provide most of the electricity produced.

Five key use cases were selected for deeper analysis based on their feasibility for e-methane and projected demand in 2040

The projected renewable gaseous molecule demand could be met by several renewable energy vectors. This study considers e-methane alongside hydrogen, ammonia and methanol. ▶H It is important to note that this is considering the form in which the molecule is consumed in the end-use conversion step. Therefore, any energy vector used as a hydrogen carrier (e.g. ammonia, LOHC or methanol) that is imported to the Netherlands and then reconverted into hydrogen before use will be represented in this overview as hydrogen, rather than the original energy vector.

E-methane could fulfill up to 80% of the renewable gaseous molecule demand in the Netherlands, but this study narrows its scope to five end-use cases[21]:

- Iron and steel
- Process heat for clusters 1-5
- Process heat for cluster 6
- Decentral heating in the built environment.
- Central dispatchable electricity production

These cases were selected based on two criteria: 1) they must be feasible for e-methane use and 2) they must have significant renewable gaseous molecule demand in 2040. For example, ammonia end-products are excluded as a feasible use case since the sector requires either hydrogen or ammonia directly as an energy vector. Although hydrogen can be produced from e-methane through steam methane reforming, using e-methane to produce hydrogen is energy and cost-inefficient, making it an uneconomic and illogical option. Together, these five use cases are forecasted to represent more than 70% of the total Dutch e-methane demand.

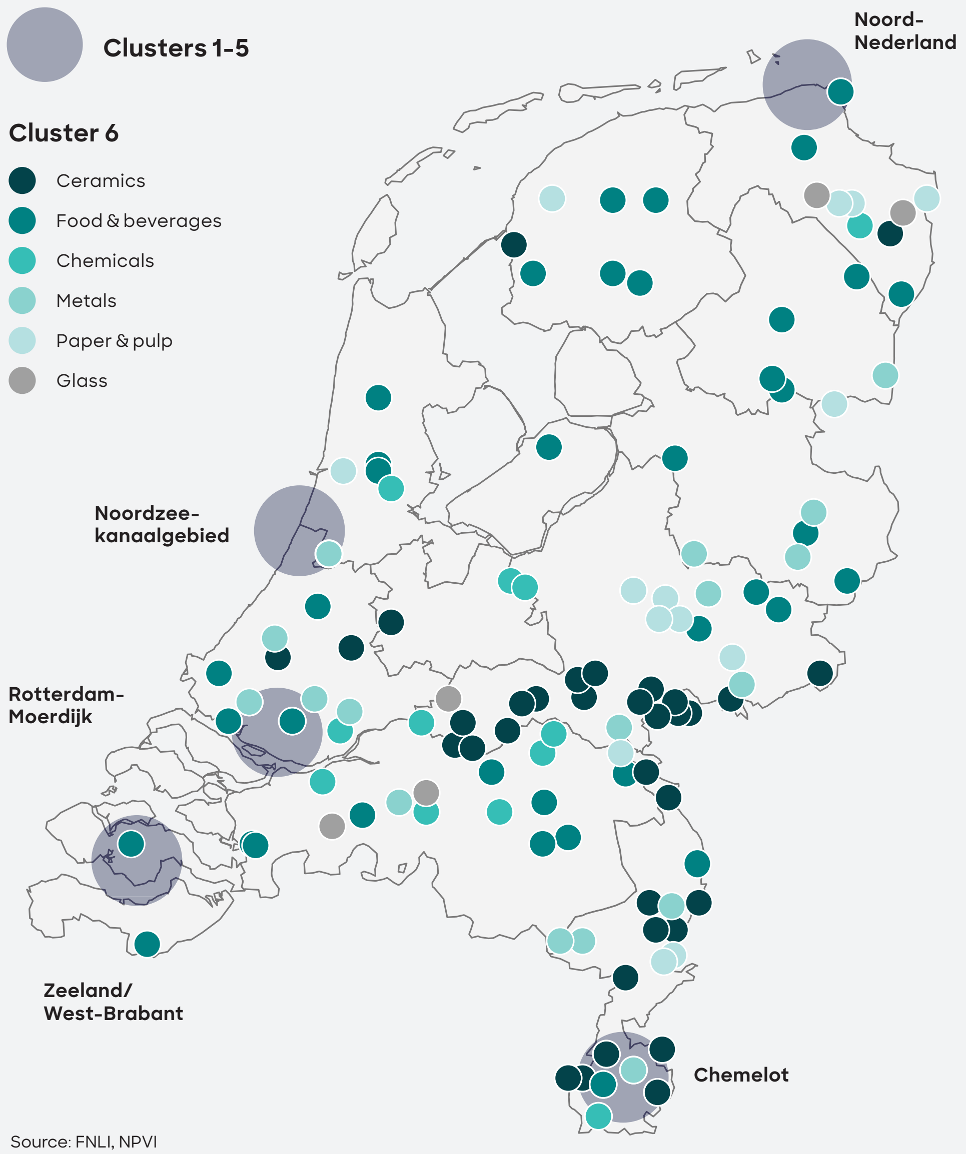
For the five selected use cases, e-methane and hydrogen are the primary energy vectors. Their roles in each value chain step are explored further.

21 Mobility is a relevant sector for e-methane; however, many use cases within this sector either have a smaller share of downstream costs in the total value chain (e.g. shipping) or would require similar new infrastructure for both e-methane and hydrogen (e.g. heavy-duty transport). Since the downstream value chain setup would not significantly differ between the two vectors, mobility use cases were not prioritized for comparison in this study

DEEP DIVE

In the Netherlands, industries are segmented into six clusters based on their geographical distribution. ▶| Clusters 1 to 5 consist of large, geographically concentrated industrial hubs that include sectors like refineries, chemicals and metallurgy. Example companies in these clusters include TATA Steel (iron and steel), OCI (chemicals), Shell (petrochemicals) and Nobian (chemicals). In contrast, cluster 6 is dispersed across the country and comprises industries such as ceramics, food and beverages, metals, paper and pulp and glass production. Examples of companies in this cluster are Wienerberger (ceramics), FrieslandCampina (dairy) and Ardagh Group (metal and glass packaging).

There are primarily six industrial clusters in the Netherlands



Source: FNLI, NPVI

Considerations of different value chain steps have been further defined for each use case for both e-methane and hydrogen

The five selected use cases are further detailed for the final value chain steps after reconversion – that is, transmission, seasonal storage, distribution and end-use conversion. ▶ J

In transmission, e-methane can utilize the existing natural gas infrastructure (HTL and RTL), while hydrogen will rely on the planned hydrogen backbone. In addition to the hydrogen backbone, some use cases, such as central dispatchable electricity production and process heat for cluster 6, may require additional pipelines to connect to the hydrogen backbone.

Seasonal storage requirements differ based on demand profiles: 40% of the demand for decentral heating is expected to go into long-term storage, ideally in depleted gas fields. For

J For the final value chain steps different considerations are relevant per use case

Produc-tion → Long-distance transportation → Recon-version → Transmission → Seasonal storage → Distribution → End-use conversion

		National transmission		Regional distribution & end-use	
		Transmission	Seasonal storage	Distribution	End-use conversion
Iron and steel	E-methane	• E-CH_4 transmission via the CH_4 HTL and RTL • H_2 transmission via the H_2 backbone[1)]	Assuming required storage capacity of 10% of annual demand	No distribution assumed due to direct connection to either CH_4 HTL/RTL pipeline or H_2 backbone	1 New asset
	Hydrogen				
Process heat for clusters 1-5	E-methane				2 Depreciated asset
	Hydrogen				
Process heat for cluster 6	E-methane				
	Hydrogen				
Electricity production	E-methane		Assuming required storage capacity of 30% of annual demand[2)]		3 Lifetime extension
	Hydrogen				
Decentral heating	E-methane		Assuming required storage capacity of 40% of annual demand[3)]	Via existing CH_4 distribution network	2 Depreciated asset
	Hydrogen			Via H_2 pipelines (assuming 50% refurbished)	1 New asset

1) Additional dedicated pipelines assumed to connect power plants and cluster 6 to the hydrogen backbone. Other options also exist, such as blending hydrogen and methane in existing pipelines; 2) To accommodate flexible electricity production in times of high electricity demand and low renewable electricity supply; 3) To accommodate storage of additional produced energy in summer for additional energy demand in winter

Source: Interviews with industry experts, Desk research central dispatchable electricity production, 30% is expected to be stored, with salt caverns being more suitable due to short-term availability needs. Industrial use cases (iron and steel, process heat) require only limited seasonal storage, with 10% expected to be stored in salt caverns[22].

Of the selected use cases, only decentral heating will require the distribution network, as the other use cases likely will be connected directly to the transmission network[23].

End-use conversion options include:

1. Purchasing new assets
2. Using existing assets that are financially depreciated but still functional
3. Investing in asset lifetime extensions

For iron and steel, only new assets are feasible as it requires moving from a blast furnace to a direct reduced iron process (option 1), while process heat and central dispatchable electricity production can use both new and existing assets with necessary adaptations for hydrogen use. It is assumed that most industrial boilers will be depreciated, but not yet at the end of their lifetime (option 2) for process heat, whereas for electricity it is assumed that most of the existing natural gas-fired power plants will require lifetime extension by 2040 (option 3). For decentral heating, e-methane can use existing natural gas boilers (option 2), while hydrogen will require new boiler installations (option 1) due to compatibility issues. For both e-methane and hydrogen, it is assumed that existing natural gas boilers are fully depreciated.

22 Storage percentage for each use case has been calculated based on input from industry experts. Central dispatchable electricity production and industrial applications are expected to require flexible, multi-cycle storage, making salt caverns the ideal choice. In contrast, depleted gas fields are better suited for long-term, single-cycle storage.

23 Some industries in cluster 6 are also connected via the distribution pipeline; however, for simplicity, this study assumes that cluster 6 is directly connected to either the HTL/RTL pipelines or the H_2 backbone

Key assumptions and boundary conditions

The study aims to provide a relative comparison of financial and non-financial parameters between energy vectors, rather than forecast absolute numbers. Standardized assumptions across energy vectors have been made to ensure a fair and consistent basis for comparison. The analysis assumes a mature, large-scale system with positive technological advancements and an optimized global supply chain by 2040

4

The Netherlands is expected to meet part of its renewable energy vector demand through imports from regions with ample, low-cost renewable energy resources capable of producing a surplus beyond local needs. These include areas like MENA, the US, southern Europe and northern Europe and, to some extent, Australia and South America. To streamline the study, the current analysis focuses on MENA, the US and southern and northern Europe as potential import hubs to meet Dutch renewable energy demands.

For medium to longer distances, transportation of the renewable energy vectors is primarily through pipelines or shipping. The choice of transportation method from these export locations is influenced by the proximity of the production region and its infrastructure. In this study, imports from southern Europe and northern Europe are assumed to utilize pipeline infrastructure. In contrast, imports from the US and MENA rely primarily on shipping. The report further assumes that all Dutch demand for renewable energy vectors will be met via these strategic import routes, ensuring a like-for-like comparison across the entire value chain.

For the selected end-use cases, energy delivered via renewable methane or hydrogen is compared

This analysis compares final energy delivered for selected end-use cases, using both methane and hydrogen as vectors. For methane, both e-methane and biomethane (in gaseous and liquid forms) are considered. For hydrogen, gaseous and liquid hydrogen are included, along with three hydrogen vectors: ammonia, methanol and LOHC, all converted back to hydrogen for end-use. Stoichiometric inputs have been assumed for each energy vector in the analysis to ensure consistency across scenarios. ▶ K

K Stochiometric inputs vary based on the type of energy vector [per MWh of energy vector produced]

Input required for 1 MWh of output						Output
Primary energy carrier	+	**Other feedstocks**	+	**Process energy input[4]**	→	**Energy vector**
1.19 MWh of H_2	per MWh of e-methane	0.19 ton of CO_2	per MWh of e-methane	<0.01 MWh	per MWh of e-methane	**1 MWh of e-methane**
0.3 ton of biomass with 5 MWh/ton of energy density	per MWh of biomethane	n/a	per MWh of biomethane	0.01[1] MWh	per MWh of biomethane	**1 MWh of biomethane**
1.19 MWh of H_2	per MWh of methanol	0.26 ton of CO_2	per MWh of methanol	0.04 MWh	per MWh of methanol	**1 MWh of methanol**
1.13 MWh of H_2	per MWh of ammonia	0.16 ton of N_2	per MWh of ammonia	0.13[2] MWh	per MWh of ammonia	**1 MWh of ammonia**
1.03 MWh of H_2	per MWh of LOHC	0.47 ton of H_0-DBT[3]	per MWh of LOHC	0.01 MWh	per MWh of LOHC	**1 MWh of LOHC (DBT)[3]**

Example

- To **produce 1 MWh of e-methane,** 1.19 MWh of hydrogen is combined with 0.19 ton of CO_2, together with <0.01 MWh of process energy input
- More than 1 MWh of primary energy carrier is required to produce 1 MWh of energy vector, as **energy is lost during the conversion process**

1) Figure comprises electricity and heat used to produce biomethane; 2) Energy consumption includes electricity needed for nitrogen separation from air; 3) LOHC = liquid organic hydrogen carrier; DBT = dibenzyltoluene, a type of LOHC; H_0-DBT = dehydrogenated DBT, H_{18}-DBT = hydrogenated DBT; 4) Only the energy required to make the energy vector is included. Any energy required to synthesize feedstock is not included here

Source: Agora, CE Delft, HyDelta, EU LCA, IEA, IRENA, Desk research

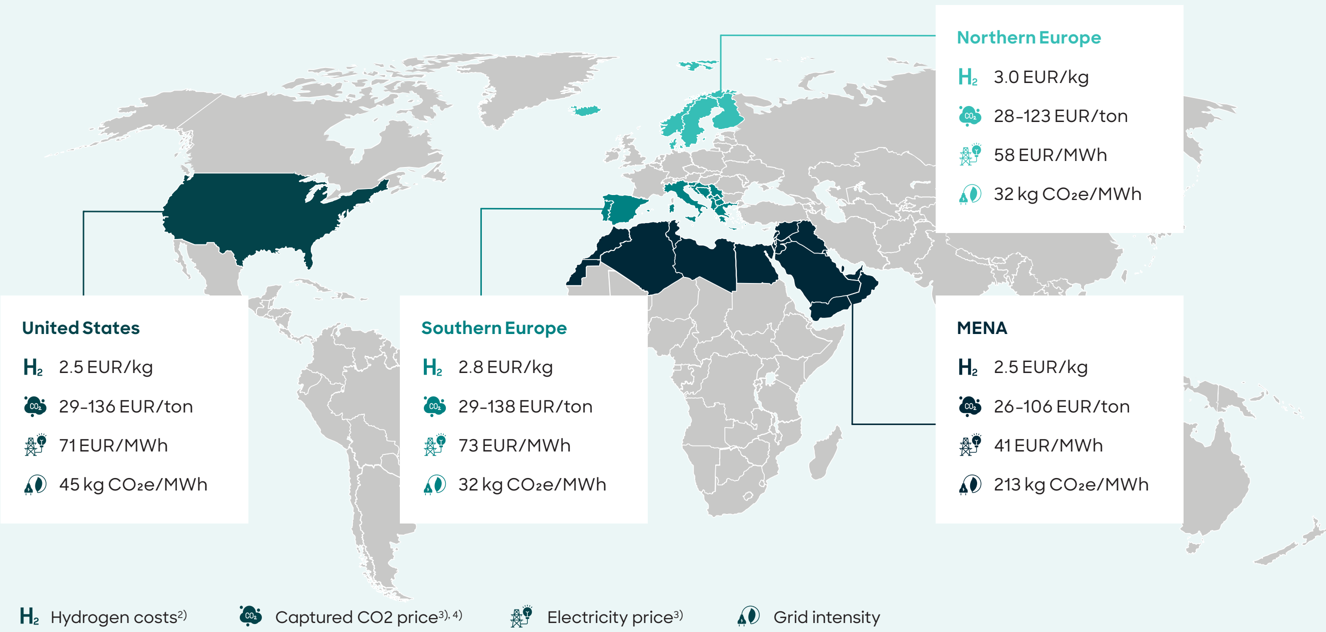
For the renewable energy vectors in scope, assumptions across the value chain have been made

This study aims to provide a relative comparison of financial and non-financial parameters between energy vectors, rather than forecast absolute numbers, as these depend on numerous factors outside the scope of the study. Most of the assumptions used throughout the value chain are based on public sources, providing a foundation for the analysis.

The renewable energy vectors evaluated also vary in maturity and are subject to technological and cost uncertainties, as some technologies have not yet been proven at an industrial scale. The analysis assumes a mature, large-scale system with positive technological advancements and an optimized global supply chain featuring centralized conversion/liquefaction and reconversion/gasification infrastructure by 2040. Consequently, assumptions for currently immature technologies are estimates of a future state and inherently carry lower confidence levels compared to those for already mature technologies. Key assumptions – such as the cost of renewable hydrogen, CO_2 capture price, electricity prices and grid emission intensity – are standardized across regions to enhance comparability[24]. ▶ L

24 For further details on assumption per energy vector per value chain step per use case, please refer to the appendix

L MENA is expected to offer competitive costs across regions for renewable hydrogen and lowest price for captured CO2 and electricity in 2040 – Grid intensity of MENA is projected to be relatively high[1)]



1) Renewable hydrogen costs for 2040 are based on the IEA forecast for 2030, with WACC at 6%, and underlying assumptions that 2030 assumptions are optimistic and forecasted price is expected to be closer to the latter half of the 2030s. CO_2 capture price estimates vary, with the lower bound representing capture from high-purity biogenic sources like bioethanol, and the upper bound reflecting DAC with energy consumption of 1 MWh per ton of CO_2 captured. In the absence of reliable electricity price data for MENA, the region's electricity price is assumed to be 60% of the US price; 2) Produced via captive renewable power; 3) Prices are based on baseload hours; 4) Study assumed TOTEX cost excl. electricity consumption of 25 EUR/ton for biogenic point-source and of 65 EUR/ton for DAC and an electricity consumption of 0.1 MWh/ton for biogenic point-source and 1 MWh/ton for DAC

Source: IEA, NETL, Natuur & Milieu, Bavarian industry association (VBW), E-bridge

The cost of renewable hydrogen follows IEA projections with a captive renewable setup, while grid electricity, with its associated emissions, is assumed for the rest of the value chain. Most of the upstream value chain – conversion to transportation (excluding pipelines) and reconversion – is modeled purely on operational costs without factoring in the cost of capital or margins. In contrast, pipeline transportation and the downstream segment, encompassing transmission, storage and distribution (regulated assets) incorporate tariffs calculated using the weighted average cost of capital (WACC), accurately reflecting regulatory conditions. WACC is excluded from the upstream segment due to varying regional risk profiles and investor return expectations, making reliable estimates challenging. This approach allows for a focused comparison of cost-competitiveness across energy vectors while respecting downstream regulatory contexts.

For long-distance maritime transportation, vessels carrying methane or liquid hydrogen are assumed to use boil-off gas as their primary fuel source, leveraging the evaporative losses from cryogenic storage to power the engines. In contrast, ships transporting ammonia and methanol will combust a portion of the cargo itself as fuel, balancing efficiency with fuel availability en route. For vessels transporting LOHC, it is assumed that e-methanol is used as fuel.

For downstream costs related to transmission, distribution via pipelines and seasonal storage within the Netherlands, bottom-up cost calculations have been conducted. These calculations are based on extensive literature reviews and stakeholder inputs to ensure that the assumptions are aligned with industry insights and the latest research. ▶ M

M Downstream costs have been assumed per value chain step [EUR/MWh] 1),2)

National transmission | Regional distribution & end-use

Production | Long-distance transportation | Reconversion | Transmission | Seasonal storage | Distribution (only for decentral heating) | End-use conversion

	Transmission	Seasonal storage: Depleted gas field	Seasonal storage: Salt cavern	Distribution (only for decentral heating)
E-methane	1.6	10	15	19
Hydrogen	1.7 3)	35	51	55

Additional costs for pipelines to connect to the hydrogen backbone: 1.4 EUR/MWh for electricity production and 16 EUR/MWh for process heat for cluster 6

1) Power plants and industrial activities in cluster 6 will require dedicated pipelines to connect to the hydrogen network, adding significant costs. Especially for cluster 6, replacing natural gas pipelines with hydrogen-compatible infrastructure introduces complexities, making pipeline costs 2-3 times higher than standard pipelines. Additionally, the limited hydrogen volumes required in this cluster 6 exacerbate the per-unit cost, resulting in a high overall cost for pipeline infrastructure in cluster 6; 2) For the hydrogen backbone, 70% refurbishment of pipelines is assumed; for all other hydrogen pipelines (additional transmission pipelines and distribution pipelines), 50% refurbishment is assumed; 3) The hydrogen tariff was calculated before the new cost estimate for the proposed Dutch hydrogen pipeline network was made public, revealing a 2.5x increase from EUR 1.5 bn to EUR 3.8 bn

Source: Roland Berger comprehensive value chain model

E-methane *van put tot pit:* a financially viable renewable energy vector

E-methane's landed costs are competitive with other renewable energy vectors when delivered in their end-use state. For hydrogen-specific applications, ammonia and liquid hydrogen offer the lowest landed cost. E-methane is cost-competitive for specific end-use cases with high downstream costs, such as decentral heating, industrial process heat for cluster 6 and central dispatchable electricity production. Large-scale e-methane production will increasingly rely on DAC to ensure stable CO_2 supplies. Consequently, DAC costs will critically determine e-methane's cost-competitiveness relative to hydrogen

5

The study analyzes renewable energy vector competitiveness through a systematic approach, first identifying optimal transport modes per import region, then evaluating total landed costs of the vectors in their end-use state and when converted to hydrogen, and finally analyzing total value chain costs for selected end-use cases. To account for key uncertainties in the assumptions, a sensitivity analysis was conducted on key parameters affecting total value chain costs. The findings of this study are also more or less relevant to neighboring countries such as Belgium, Germany and others that share a similar reliance on natural gas and are likely to require substantial imports to meet their future renewable energy needs.

Transporting renewable energy vectors via pipelines is expected to be the most cost-competitive method for shorter distances, provided that sufficient volumes are transported. For medium to longer distances, shipping will be more cost-competitive

Long-distance transportation options depend mainly on the distance between export and import locations. Pipelines are more cost-competitive for shorter distances, while maritime shipping is more cost-competitive over medium to longer distances. Pipeline costs rise in line with distance, whereas the high initial costs of shipping (e.g. liquefaction, gasification) are offset over longer routes, with only fuel and operational expenses adding incrementally. According to model-based calculations, the tipping point[25] for methane transportation is around 1,500-2,000 km, while for hydrogen it is around 5,000-6,000 km, reflecting hydrogen's higher upfront costs for liquefaction or conversion (e.g. to ammonia). Liquid hydrogen is expected to have a lower upfront cost compared to other hydrogen derivatives, making it more cost-competitive for delivering hydrogen over short to medium distances. ▶ N

In practice, the tipping point is situation-specific and influenced by various factors. For example, shipping can be viable over shorter distances, as border crossings and intercontinental links can complicate pipelines and increase costs. Additionally, pipelines are typically cost-competitive only for large volumes, making shipping more attractive, particularly in the short term when volumes are lower. Conversely, if existing pipelines are already in place, the tipping point for pipeline transportation could be later than indicated.

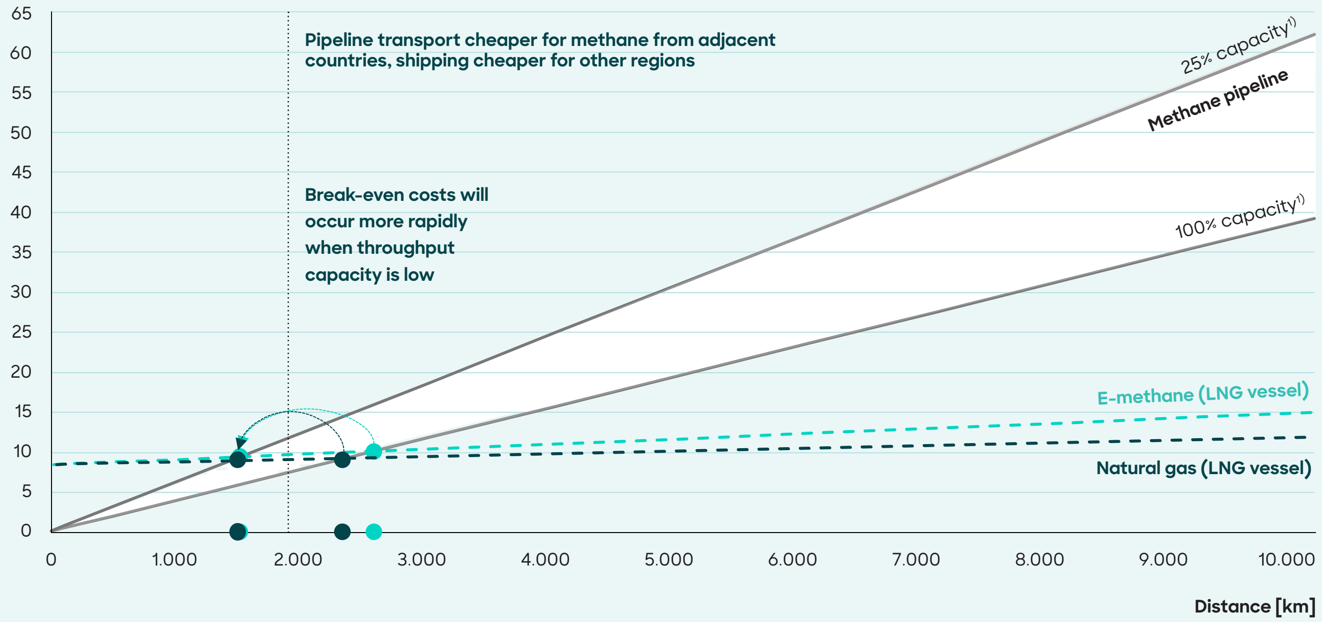
As a result, renewable energy vectors from southern Europe and northern Europe are likely to be shipped initially, with pipelines taking over in the long term, while those from MENA and the US are expected to use shipping in both the short and long term. Factoring in production and transportation, MENA and the US are anticipated to be the most cost-competitive sources of e-methane, while southern Europe likely to be the most cost-competitive for hydrogen. ▶ O

To mitigate risks like supply chain disruptions, political instability and feedstock limits, diversifying export regions is essential. To ensure consistency across different vectors, the remainder of this analysis will use MENA as the primary export region for renewable energy

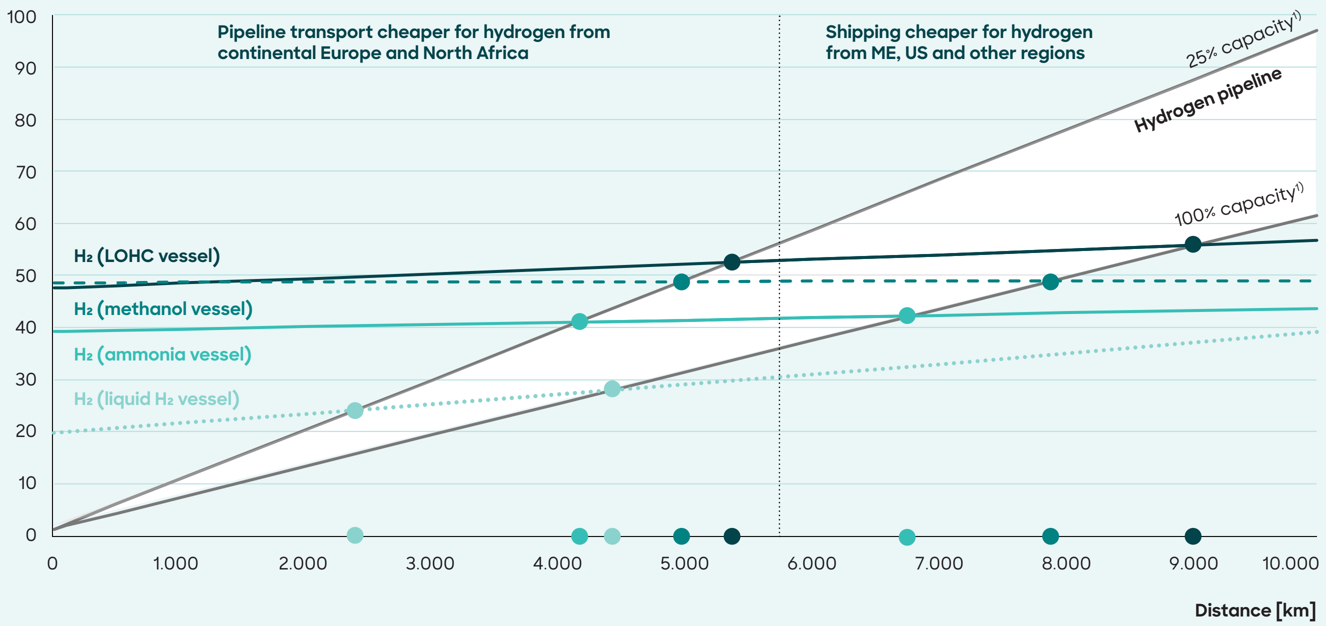
25 Shipping costs include conversion, storage, transportation and reconversion costs. Within conversion, it also accounts for the cost of the additional feedstock required compared to gaseous vector to deliver same amount of landed energy. As explained earlier, shipping costs are modeled purely on an operational cost basis without including WACC, whereas pipeline costs are tariff based and account for WACC as regulated assets. Accounting for WACC in shipping would slightly increase the tipping point

N **Transporting renewable energy vectors via pipelines is more cost-competitive for shorter distances, whereas for medium to longer distances shipping becomes more cost-competitive**

Projected transportation cost of methane [EUR/MWh output]



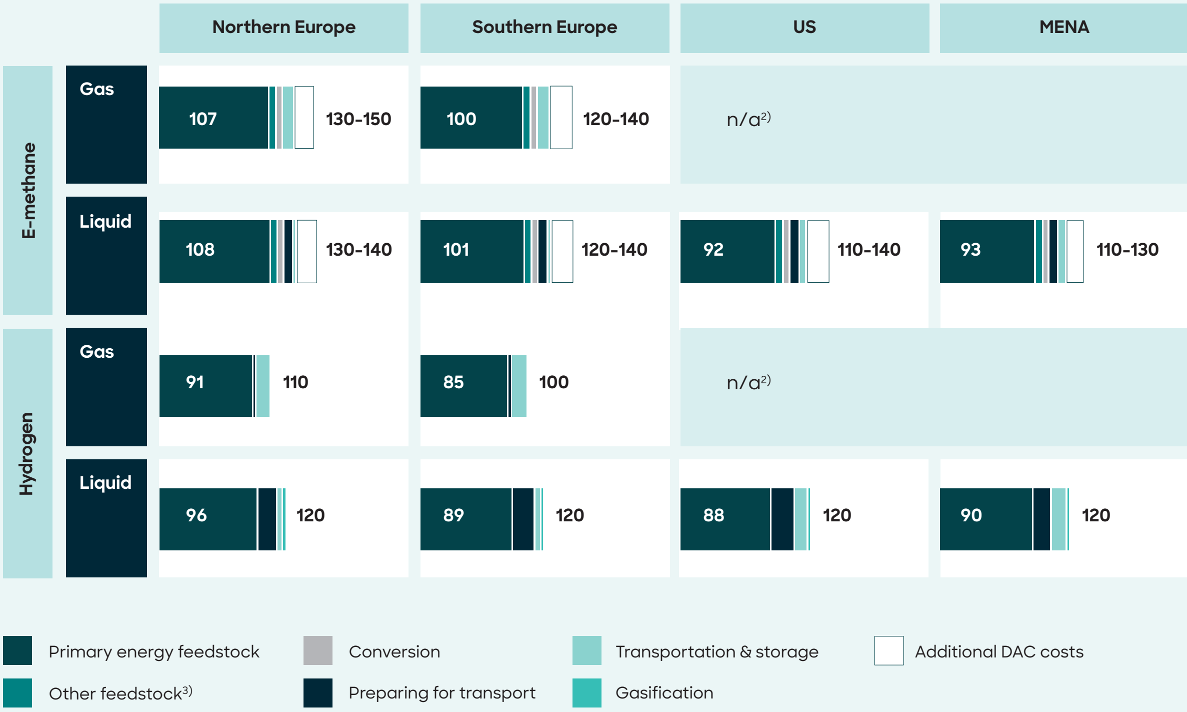
Projected transportation cost of hydrogen [EUR/MWh output]2)



1) Total pipeline capacity of 163 TWh for methane and 147 TWh for hydrogen; 2) Includes conversion and reconversion

Source: Roland Berger comprehensive value chain model

Liquid route from MENA and US is expected to be the most cost-competitive for e-methane whereas importing via pipelines from southern Europe seems to be most attractive for hydrogen [EUR/MWh output][1)]



1) Total costs are rounded to nearest multiple of 10 in all the financial comparison analyses; 2) Pipeline transport of gases not considered for the US and MENA, as the distance for gas pipelines is too long and in that situation pipeline transport becomes significantly more expensive than shipping of liquids; 3) Includes CO_2 for e-methane and methanol, N_2 for ammonia and dehydrogenated DBT for LOHC

Source: Roland Berger comprehensive value chain model

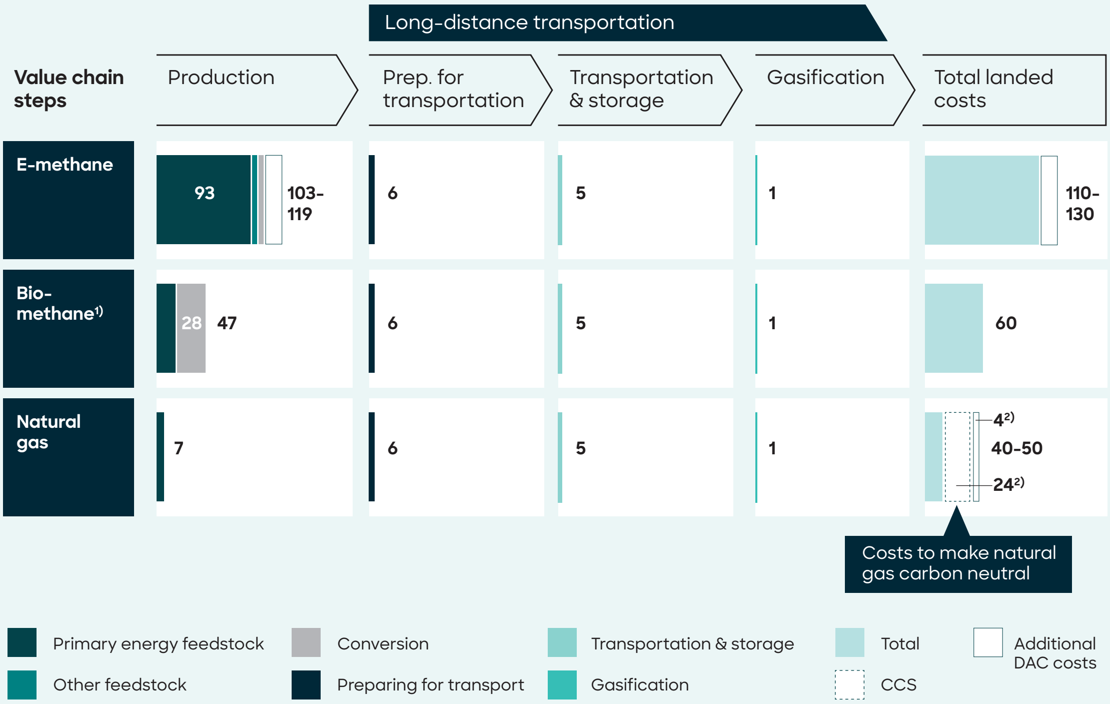
vectors, with shipping as the assumed transportation mode[26]. It is important to note that, for all remaining financial analyses in this chapter, costs are shown per MWh output at the last value chain step in the figure. Due to losses throughout the value chain, numbers might not correspond between figures. The different efficiencies at end-use conversion associated with different use cases also explain the varying costs per use case.

Importing e-methane will come at a premium compared to CO_2 compensated natural gas. Large-scale production of e-methane will increasingly need to rely on DAC to ensure stable CO_2 supplies, as biogenic CO_2 availability is expected to be limited in long term

Natural gas, with production costs typically well below 10 EUR/MWh, is expected to remain one of the most affordable energy vectors, also when considering the cost of capturing and

26 Total costs are rounded to nearest multiple of 10 in all the financial comparison analyses. All financial analyses show costs and efficiencies with biogenic CO_2. Additional DAC feedstock costs are shown separately in the production step. The overall efficiency of e-methane with DAC is about 10% lower than with biogenic CO_2

P Natural gas is expected to remain one of the most affordable energy vectors [EUR/MWh output]



1) Based on anaerobic digestion; 2) The combustion of 1 MWh of natural gas emits ~ 0.19 ton of CO_2 per MWh. CCS is assumed to occur at the end-use location in the Netherlands, while DAC is expected to take place at the export location in MENA. Costs to capture CO_2 in NL are expected to be ~66 EUR/ton for point source with additional transport & storage costs of 60 EUR/ton and DAC in MENA is expected to have a cost of 106 EUR/ton for capture with additional transport & storage costs of 40 EUR/ton

Source: Roland Berger comprehensive value chain model

storing the CO_2 created during combustion. ► P With rising demand for greener alternatives, biomethane and e-methane are emerging as viable options that utilize existing infrastructure. Biomethane is generally more cost-competitive due to lower feedstock costs, though its large-scale production is limited by feedstock availability, which competes with food production, animal feed and agriculture. Feedstock supply is also influenced by geography, seasonality and sustainability factors. In contrast, e-methane can be produced from virtually unlimited renewable sources like sun and wind, making it a scalable supplement to biomethane.

E-methane produced from biogenic CO_2 has lower production costs than CO_2 from DAC, but biogenic CO_2 availability is also limited. By 2040, global biogenic CO_2 supply is projected to be at 400-500 Mt[27]. Just meeting Dutch demand of 25 Mt of CO_2 for e-methane in 2040 would require 6-8% of expected global biogenic CO_2 supply, 12-15% of US and a staggering 150-160% of the expected MENA, illustrating the insufficiency of relying solely on biogenic sources. Therefore, while e-methane with biogenic CO_2 has potential, large-scale production will increasingly need to rely on DAC to ensure stable CO_2 supplies long term – the same applies to methanol.

27 IEA, Zero Carbon Shipping

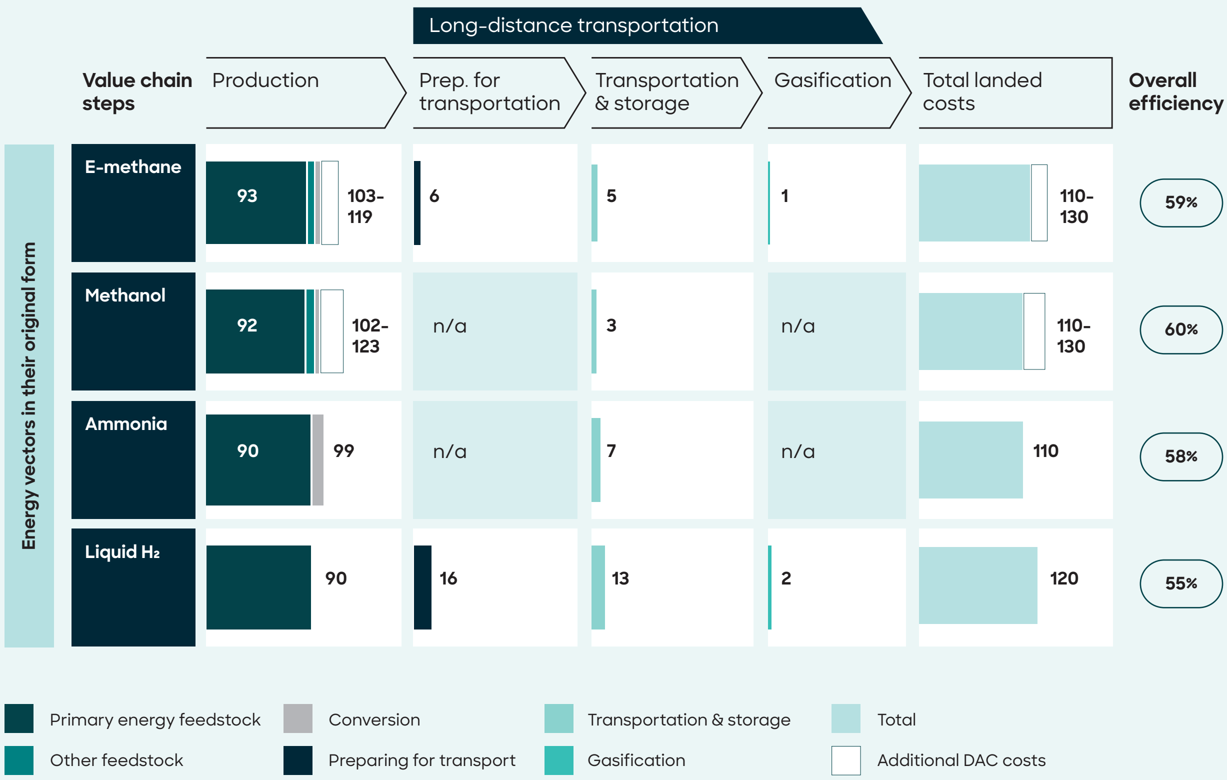
Landed cost of e-methane is in line with other renewable energy vectors. Production and shipping of renewable energy vectors most cost-competitive when already in end-use state

The landed cost[28] of e-methane is comparable to that of other renewable energy vectors. ▶ Q When produced with biogenic CO_2, e-methane costs are comparable to methanol and ammonia. However, sourcing CO_2 from DAC increases the cost of e-methane by 20-25% compared to ammonia. Despite this increase, e-methane remains cost-competitive with other renewable energy vectors as higher production costs are offset by relatively lower long-distance transportation cost.

Shipping renewable energy vectors in their original form is more cost-competitive than synthesizing them in the Netherlands from imported hydrogen, regardless of distance and the shipping method. This advantage arises because transportation costs typically account for only 5-10% of the total landed costs and are more than offset by the higher energy prices in the Netherlands compared to the production location. For instance, synthesizing ammonia or

28 Costs from production up to and including transportation to the import location

Q Landed cost of e-methane is cost-competitive with other renewable energy vectors [EUR/MWh output]



Source: Roland Berger comprehensive value chain model

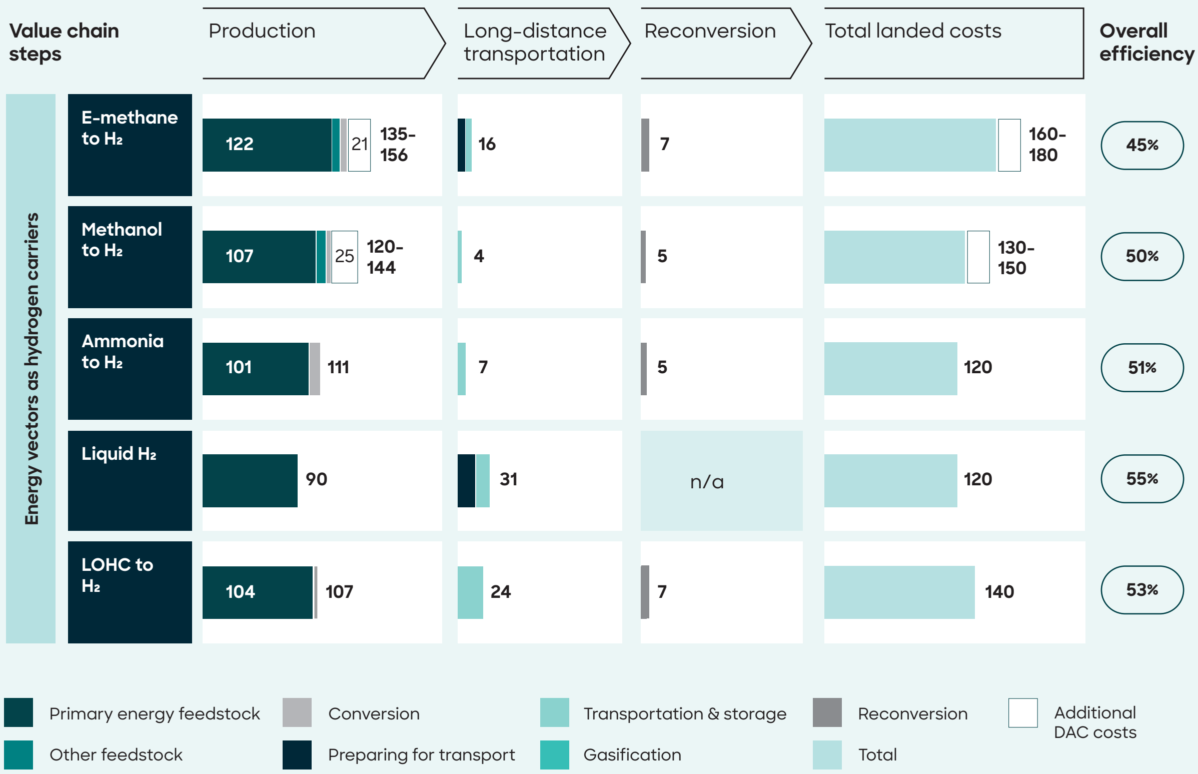
methanol in the Netherlands using imported hydrogen is 20-30% more expensive than importing the already synthesized vectors from regions like MENA. As a result, there is a possibility that production of these renewable energy vectors, such as ammonia and methanol, will shift from the Netherlands to regions where energy prices are lower, such as MENA.

If hydrogen is the required energy vector for end-use, ammonia and liquid hydrogen are expected to offer the lowest cost levels

As some sectors like refineries specifically require hydrogen for their operations, the procurement of renewable hydrogen for end-use will be necessary in the future. Comparing the landed costs of various energy vectors for hydrogen, ammonia and liquid hydrogen are projected to have comparable costs, followed by methanol and LOHC. ▶ R

The landed costs of ammonia and methanol are primarily driven by the production steps of each vector, with ammonia outperforming methanol due to its lower hydrogen feedstock requirements and the absence of the need for GHG-neutral CO_2. In contrast, the cost of

R If hydrogen is the end requirement, ammonia and liquid hydrogen are expected to have the lowest costs [EUR/MWh output]



Source: Roland Berger comprehensive value chain model

liquid hydrogen is predominantly influenced by long-distance transportation, including liquefaction and gasification. LOHC is relatively more expensive than ammonia and liquid hydrogen, primarily due to its lower volumetric energy density, which results in higher transportation costs per MWh. Additionally, the dehydrogenation process incurs high conversion losses and energy demands, further increasing its overall cost. Lastly, if used as a hydrogen carrier, e-methane is the least cost-competitive and energy-efficient carrier, primarily due to the costs associated with its synthesis. These high production costs, combined with its lower energy efficiency, make e-methane a less viable option if hydrogen is the required energy vector for end-use in the Netherlands.

Even with CO_2 from DAC, which is likely required due to the limited long term availability of biogenic CO_2, e-methane is still cost-competitive for certain use cases where downstream costs of storage, distribution, and end-use conversion make up a relatively higher share of total costs in the value chain

The comparison of the total costs includes the downstream value chain steps of transmission, seasonal storage, distribution and end-use conversion. ▶S Comparison depends on the specific end-use case. For the five selected use cases, e-methane sourced as a liquid from MENA via vessels is compared with hydrogen transported from MENA. The analysis assumes hydrogen is delivered as ammonia but acknowledges that it could also be transported as liquid hydrogen, given the comparable landed costs of the two vectors.

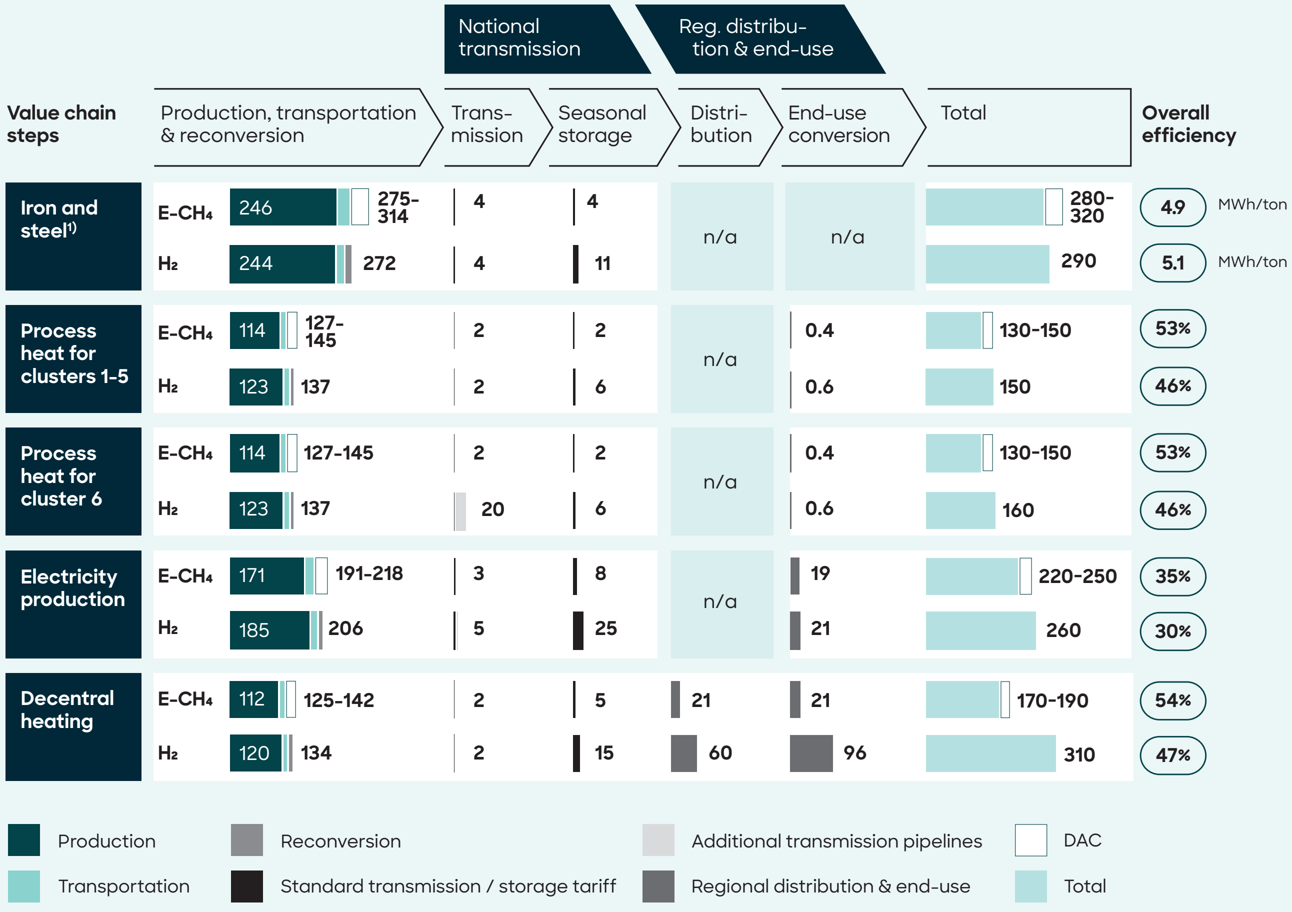
While e-methane with biogenic CO_2 is expected to be more cost-competitive than hydrogen across all shortlisted end-use cases, there are limitations. As mentioned earlier, biogenic CO_2 availability is limited due to feedstock constraints. This will likely restrict the scalability of e-methane with biogenic CO_2 for large-scale applications. Although e-methane from DAC incurs higher costs compared to biogenic CO_2, it still has a cost advantage over hydrogen for decentral heating, process heat for cluster 6 and central dispatchable electricity production. For process heat in clusters 1-5, e-methane with DAC is cost-comparable to hydrogen, while hydrogen remains more cost-competitive for iron and steel production.

E-methane mainly has a cost advantage over hydrogen in specific use cases with higher downstream value chain costs, as existing infrastructure can be leveraged, reducing associated expenses. For example, decentral heating with hydrogen would require adapting 80% of the existing distribution network (equivalent to 100,000 km[29]) and upgrading 2.5 m boilers[30], resulting in significant additional costs compared to e-methane, which can use the existing infrastructure. Seasonal storage costs for hydrogen are three times higher than for e-methane, primarily due to e-methane's three times higher volumetric energy density, which reduces storage costs for decentral heating and central dispatchable electricity production. In process heat for cluster 6, the hydrogen route would require an additional

29 Netbeheer Nederland indicates 136,000 km of gas network in the Netherlands, 11,000 km of which is for transmission, according to Gasunie. The remaining 125,000 km is distribution network and 80% of 125,000 km results in 100,000 km of distribution network remaining

30 Based on II3050, considering the International Trading (INT) scenario

S E-methane as an end-product with biogenic CO_2 is cost-competitive with hydrogen for all use cases, whereas with DAC it is cost-competitive in cluster 6, electricity production and decentral heating due to the lower infrastructure costs for e-methane [EUR/MWh output]



1) Values for iron and steel shown in EUR/ton steel

Source: Roland Berger comprehensive value chain model

400 km of dedicated pipeline[31], adding 18 EUR/MWh in transmission costs. E-methane, however, can utilize the existing transmission network without additional costs for new pipelines to connect to certain end-users.

The current analysis focuses on e-methane synthesized at the export location and transported to the Netherlands. Alternative routes include capturing CO_2 at the combustion site and returning it to the export location or capturing CO_2 at the end-use site and storing it

31 HyRegions: Approach for the possible roll-out of regional hydrogen infrastructure

in the Netherlands. Both alternatives are cost-comparable, but the latter may offer cost advantages when carbon deposit removal fees exceed 180-200 EUR/ton[32].

In the broader context of low-carbon energy vectors, fossil vectors with CCS are generally expected to be more cost-competitive than renewable energy vectors if they run at high utilization rates. When comparing different fossil vectors with CCS, natural gas combined with CCS is expected to be more cost-competitive than blue hydrogen, because it is cheaper to transport natural gas and CO_2 than to transport hydrogen. Consequently, even when considering low-carbon alternatives, hydrogen pathways remain less cost-competitive than low-carbon/renewable methane-based vectors, solidifying methane's role as a less costly option for selected use cases.

Since e-methane is expected to be more cost-competitive in certain use cases, it could reduce the total future demand for renewable hydrogen in the Netherlands, particularly in applications like decentral heating, process heat and central dispatchable electricity production. This reduction in the Dutch demand for hydrogen would in turn lead to higher transmission and distribution tariffs, as the infrastructure costs would need to be distributed across a smaller user volume. However, in practice, reduced hydrogen demand within the Netherlands could be offset by increased export capacity to neighboring regions like Germany, potentially minimizing the impact on tariffs.

The costs of DAC play a key role in determining the degree of cost-competitiveness of e-methane with respect to hydrogen

All renewable energy vectors in this study face uncertainties, including the costs for renewable hydrogen, prices for electricity and captured carbon, technology maturity and demand-related tariffs. A sensitivity analysis was conducted on key parameters affecting total value chain costs, such as hydrogen costs, DAC prices, electricity prices and transmission tariffs. Sensitivity on transmission tariffs reflects the uncertainty in the demand of e-methane and hydrogen. If the demand reduces by half, the tariffs will increase by factor of two (assuming pipelines are primarily used for domestic demand). ▶ T

Although uncertainty in renewable hydrogen costs significantly impacts total costs, it does not affect e-methane's cost-competitiveness in most cases, as the hydrogen costs make up over 55% of production costs of all of the renewable energy vectors. Uncertainty in DAC price has the biggest impact on cost-competitiveness; as DAC price doubles, hydrogen becomes more cost-competitive in all cases except decentral heating, where e-methane remains more cost-competitive due to high hydrogen-related costs at later stages of the value chain. Initially, e-methane can use the more cost-competitive biogenic CO_2, but as demand grows, the CO_2 from DAC will become a crucial feedstock, making DAC pricing a key factor in e-methane's long-term cost-competitiveness. With DAC still at a lower technological maturity level (TRL 6),

32 Alternative routes for electricity production and process heat in clusters 1-5 have been analyzed. For electricity production, it is assumed that the carbon capture unit increases the CAPEX and OPEX of the electricity plant by 75%. For process heat in clusters 1-5, the CAPEX for the carbon capture facility is assumed to be 250 EUR per ton of CO_2 captured, with an OPEX rate of 4%. Shipping costs are estimated at 40 EUR per ton of CO_2, while transportation and storage costs are estimated at 60 EUR per ton

its scalability and cost trajectory remain uncertain, underscoring the importance of investments in its technology to ensure e-methane's future cost-competitiveness.

The current analysis focuses on energy demand based on the INT scenario outlined in the II3050 report. When other scenarios are considered, the total demand for renewable energy vectors changes, which primarily influences transmission tariffs. However, these changes in transmission tariffs do not affect the relative cost-competitiveness of the energy vectors. Even when transmission tariffs are doubled, the conclusions regarding the comparison between e-methane and hydrogen remain unchanged. This suggests that selecting a different II3050 scenario with varying energy demand would not significantly affect the conclusions on the cost-competitiveness of renewable energy vectors.

T Cost of hydrogen has the highest impact on the total costs of energy vectors but has less effect on their competitiveness compared to the significant influence of DAC price on cost-competitiveness [EUR/MWh output][1)]

Reflects demand uncertainty (Transmission tariff)

		Base case	Hydrogen costs: 1.25 ← 2.5 → 5.0 EUR/kg			DAC price for CO_2: 80[5)] ← 106 → 212 EUR/ton			Electricity price[3)]: 41-92 → 82-184 EUR/MWh			Transmission tariff[4)]: 1.6-17.7 → 3.2-35.4 EUR/MWh
			Decrease	Increase	Break-even	Decrease	Increase	Break-even	Increase		Break-even	Increase
Iron and steel[2)]	E-CH_4	320	-35%	+69%		-4%	+16%		+1%			+1%
	H_2	290	-39%	+77%		n/a	n/a		+8%			+1%
Process heat for clusters 1-5	E-CH_4	150	-35%	+69%	3.7	-4%	+16%	88	+1%		58-132	+1%
	H_2	150	-38%	+77%		n/a	n/a		+8%			+1%
Process heat for cluster 6	E-CH_4	150	-35%	+69%		-4%	+16%	168	+1%			+1%
	H_2	160	-34%	+69%		n/a	n/a		+7%			+12%
Electricity production	E-CH_4	250	-31%	+63%		-4%	+14%	137	+2%			+1%
	H_2	260	-33%	+65%		n/a	n/a		+7%			+2%
Decentral heating	E-CH_4	190	-27%	+53%		-3%	+12%		+1%			+1%
	H_2	310	-18%	+36%		n/a	n/a		+3%			+1%

Most cost-competitive option, **both** in base case and with changed parameter

Most cost-competitive option, **not** in base case but only with changed parameter

xx Break-even price/costs

1) Considering import of liquid e-methane with DAC and ammonia (to hydrogen) via shipping from MENA, 2040 forecast; 2) Values for iron and steel shown in EUR/ton steel; 3) 41 EUR/MWh in MENA and 92 EUR/MWh in the Netherlands; 4) Depending on energy vector and use case. If multiple tariffs were considered, which is the case for the additional pipelines for cluster 6 and central dispatched electricity production, all tariffs were multiplied by 2 for the sensitivity analysis; 5) Theoretical minimum of DAC costs

Source: Roland Berger comprehensive value chain model

Comparing e-methane with other energy vectors on criteria beyond cost

Given the capital-intensive nature of the energy transition, the adoption of e-methane allows for the reuse of existing infrastructure, conserving financial and human resources while minimizing delays. With lower upfront costs, e-methane enhances societal value and enables a more resource-efficient energy transition. Its viability is further bolstered by its positive emissions impact, safety advantages and efficiency in land use and logistics

6

In addition to the landed and total costs of energy vectors discussed in Chapter 5, this study also compares energy vectors across other key parameters, such as infrastructure needs and costs, emissions and safety to evaluate their long-term feasibility. Infrastructure costs and technology readiness levels are key to determine how to meet GHG targets sooner rather than later, influencing timelines and investment needs. Assessing GHG emissions across the value chain and the cost per ton of CO_2 saved identifies the most cost-competitive decarbonization pathways. Safety and land-use analyses highlight feasibility, costs and compliance requirements of the energy vectors.

In the Netherlands, for the selected use cases, the hydrogen route will require an additional EUR 63 billion in CAPEX compared to the e-methane route

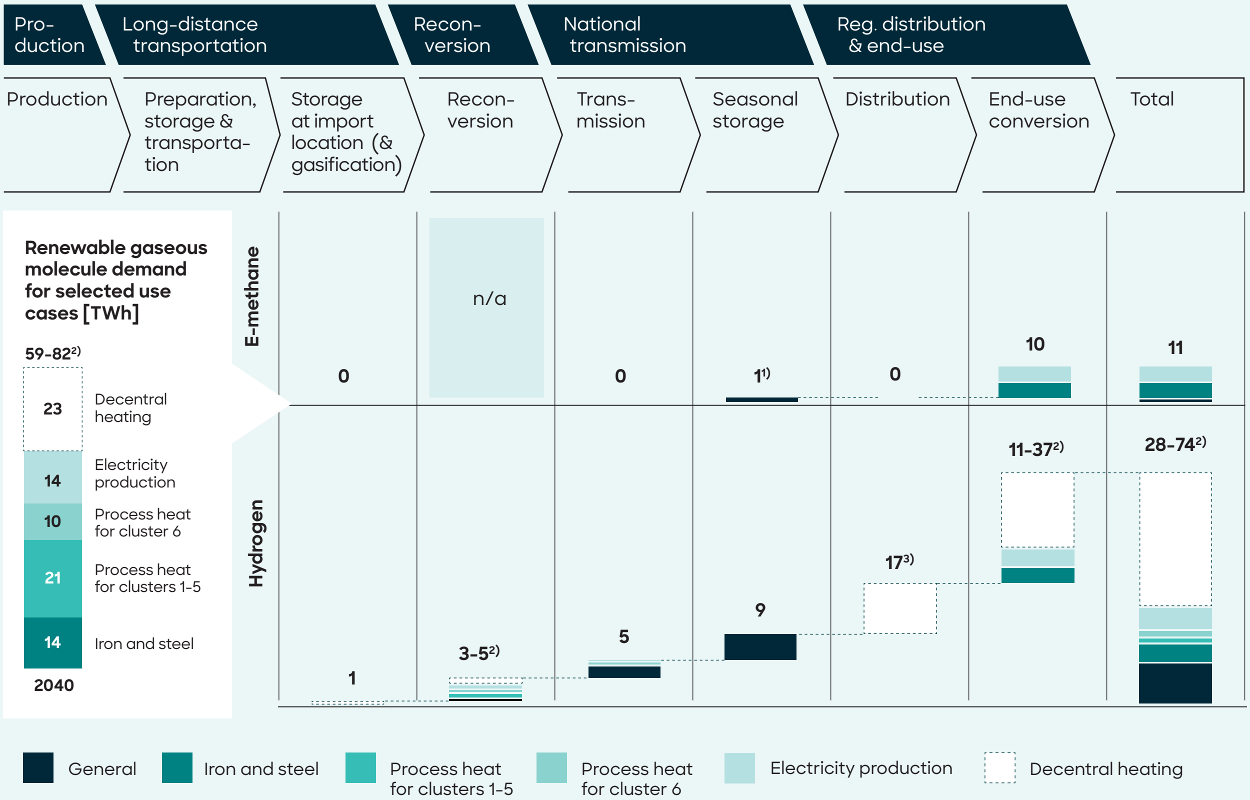
The total CAPEX investment required in the Netherlands to meet renewable energy vector consumption shows that hydrogen consumption costs are estimated at EUR 74 billion across the five selected use cases – significantly higher than the EUR 11 billion needed for e-methane (imported in liquid form). ▶U This cost disparity largely stems from the Netherlands' existing methane infrastructure, which spans the entire value chain from storage at import terminals to end-use conversion, whereas hydrogen infrastructure would need to be built almost entirely from scratch, except for the share of existing pipelines that can be repurposed for hydrogen. In regions with a less developed methane infrastructure, this cost disparity will likely be less pronounced.

For the use of hydrogen, decentral heating accounts for a substantial portion of CAPEX, totaling EUR 45 billion. Due to e-methane's significant cost advantage and the option to use biomethane and hybrid heat pumps, decentral heating is unlikely to transition to hydrogen. Excluding decentral heating from hydrogen's investment needs reduces total hydrogen CAPEX to EUR 28 billion, still almost triple the EUR 11 billion needed for e-methane.

In the remaining four use cases, most additional costs for hydrogen arise from seasonal storage, transmission and reconversion. For example, in seasonal storage, e-methane would require EUR 1 billion to expand flexible storage in salt caverns[33], increasing the current capacity of 3.6 TWh to 11 TWh. In contrast, hydrogen would require EUR 4 billion to adapt existing salt caverns and develop new hydrogen storage capacity. Also developing new hydrogen storage capacity for longer periods in depleted gas fields would cost EUR 5 billion, leading to a total investment cost of EUR 9 billion. The large difference in required investments is not only due to the fact that much of the methane storage infrastructure is already in place. Also, less TWh of hydrogen can be stored in a salt cavern than methane, as the volumetric energy density of hydrogen is only one-third that of methane. Therefore, relatively more salt caverns are required for hydrogen storage, increasing the hydrogen costs per MWh for seasonal storage.

33 While there is currently sufficient methane storage capacity in depleted gas fields (136 TWh), this type of storage is mainly suitable for long-term storage. It is expected that in the future, more short-term storage capacity is required, for which salt caverns would be more suitable; there is currently only 3.6 TWh capacity compared to the 11 TWh capacity expected to be required

U **CAPEX intensity of meeting hydrogen demand in the Netherlands is three times higher than that of e-methane, even when excluding decentral heating costs [EUR bn]**



1) Additional methane storage required specifically for salt caverns for higher flexibility; 2) Low end of the range shows total required CAPEX without decentral heating; 3) Distribution only required for decentral heating

Source: Roland Berger comprehensive value chain model

A recent study by the Dutch Ministry of Economic Affairs indicated that by 2050, up to 60 salt caverns will be required to accommodate the storage needs for hydrogen[34].

E-methane adoption enhances societal value, enabling a more resource-efficient energy transition

Given the capital-intensive nature of the energy transition, exploring alternatives that reduce the societal burden with lower upfront costs is crucial. The adoption of e-methane allows us to reuse existing infrastructure, conserving both financial and human resources and minimizing the risk of delay. In addition, e-methane can also serve as a transition energy vector in other use-cases by using it as a drop-in for natural gas. This facilitates the transition

34 Risk assessment for Underground Hydrogen Storage (UHS) in Salt Caverns and Interaction with other Underground Storage Locations, KEM, 2023

to renewable energy vectors through longer use of the existing natural gas infrastructure throughout the entire value chain. This efficient use of resources and infrastructure amplifies e-methane's societal value, freeing capital and attention for other critical strategic priorities.

Majority of the renewable energy vectors considered in the study are expected to achieve full commercial readiness by 2040

TRL scores indicate the development stage of a technology, from research and development (TRL 1-3) to full commercial deployment (TRL 11). Understanding these scores is needed for assessing when different energy vectors can be widely adopted. The technological maturity of different energy vectors varies by value chain step. ▶ V Renewable methane vectors are generally more mature than hydrogen vectors as they can leverage fully commercially mature existing gas infrastructure, apart from the production step, which has yet to achieve commercial maturity. For hydrogen, the ammonia vector is the most technologically mature, primarily due to the well-established infrastructure for ammonia synthesis, storage and transportation at scale. However, all renewable energy vectors face technological uncertainties and lower maturity in different parts of their value chains. E-methane, for example, still requires further development in areas like DAC and conversion processes. Similarly, further advances in ammonia cracking technology will be required to mature the ammonia route. Despite these technological uncertainties, all renewable energy carriers currently operate at a TRL level above the prototype stage (TRL 4) and for the purpose of this study are assumed to reach commercial technological readiness by 2040.

E-methane and renewable hydrogen have comparable GHG emission intensities

E-methane and renewable hydrogen have similar landed GHG emission intensities[35,36], ranging from 20 to 80 kg CO_2e/MWh, but the sources of these emissions vary. Emissions from methane-based vectors are both scope 1 and scope 2, where scope 1 emissions are due to methane and hydrogen slips, and emissions from hydrogen vectors are largely scope 2, influenced by grid CO_2 intensity. As the vectors are net-zero, scope 1 CO_2 emissions are not considered. Across both vectors, the production stage is the primary source of emissions, with minimal impact from transportation (except for liquid and gaseous hydrogen, where energy-intensive liquefaction and hydrogen leakage in pipeline transportation, based on current insights, significantly contribute to transportation emissions). ▶ W

Emissions for e-methane and methanol rise when CO_2 is sourced from DAC due to the energy intensity of the process. Similarly, ammonia emissions are driven by its energy-intensive synthesis. As a result, all three vectors have higher scope 2 CO_2 emissions as the grid

35 Emissions are converted to CO_2 equivalent using the 100-year Global Warming Potential (GWP_{100}); methane is assumed to have a GWP_{100} of 27, hydrogen of 11.6, N_2O of 273 and NOx of 8.5

36 In all emissions analyses in this chapter emissions are shown per MWh output at the last value chain step shown in the figure. Due to losses throughout the value chain, numbers might therefore not correspond between figures. Some value chain steps are relatively small compared to other steps, making them difficult to visualize in a graph. All emissions analyses show emissions with biogenic CO_2. Additional DAC feedstock emissions are shown separately in the production step and in the final totals

V Renewable methane vectors have relatively higher technology maturity level compared to hydrogen vectors[1)]

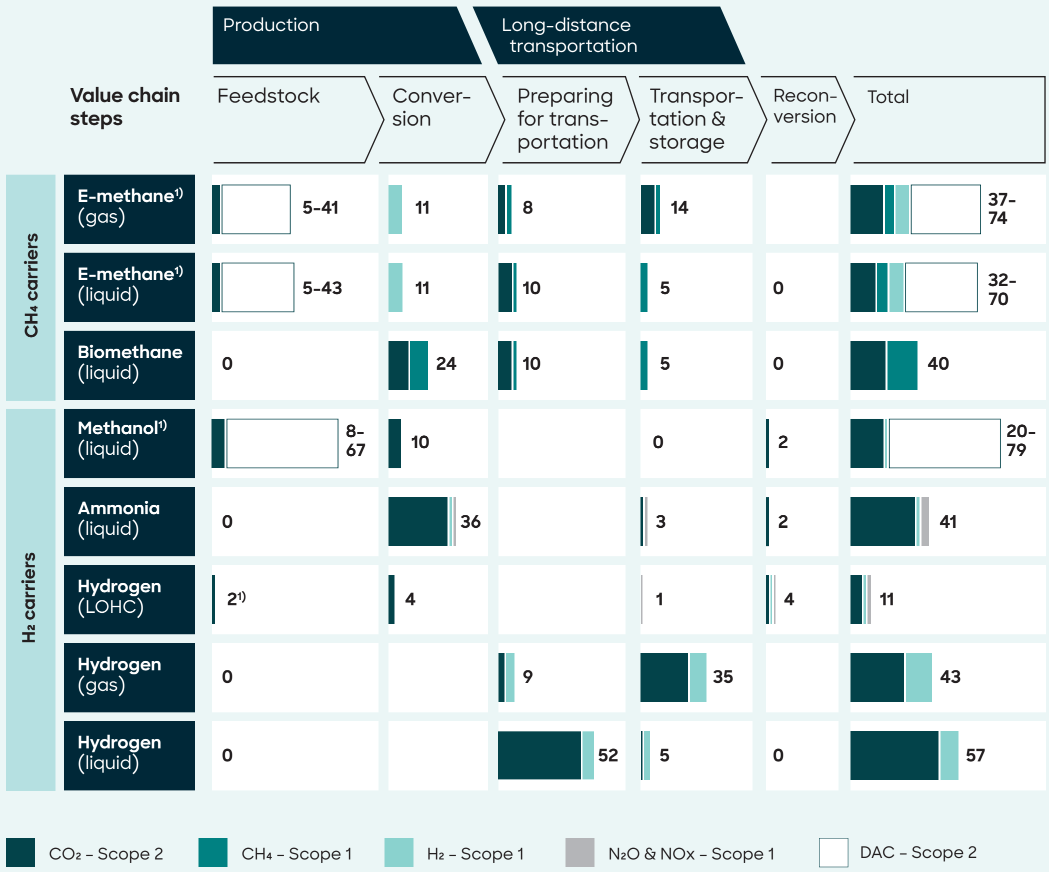
Value chain steps	Production			Long-distance transportation					Recon-version	National transmission		Reg. distribution & end-use	
	Production	Other feed-stocks	Conversion	Preparing for transporta-tion	Storage at production location	Transporta-tion[6)]	Storage at import location	Gasification	Reconversion	Transmission	Seasonal storage	Distribution	End-use conversion
Natural gas (liquid)	Extraction: **11**			Liquefaction: **11**	Storage at production: **11**	Shipping: **11**	Storage at import: **11**	Re-gasification: **11**	Conversion to H_2: **11**	National gas grid (HTL & RTL): **11**	Seasonal storage **11**	Local gas grid: **11**	Iron and steel: **9**
E-methane (gas)	Electrolysis: **9**	Carbon capture: **6-11**[2)]	Methanation: **7**	Compression: **11**		Pipeline: **11**							
E-methane (liquid)				Liquefaction: **11**	Storage at production: **11**	Shipping: **11**	Storage at import: **11**	Re-gasification: **11**					Process heat, electricity production, Decentral heating: **11**
Biomethane (liquid)	Bio feestock		Methanation: **10-11**										
Methanol (liquid)	Electrolysis: **9**	Carbon capture: **6-11**[2)]	Methanol synthesis: **9**[4)]		Storage at production: **11**[3)]	Shipping: **11**[5)]	Storage at import: **11**[3)]		Conversion to H_2: **4-6**[5)]	Local H_2 grid: new **9**, refurbished **8**	Seasonal storage: **4-10** Depleted gas field storage: **4** Salt cavern storage: **9-10** We assume NL will make use of both storage types	Local H_2 grid: new **9**, refurbished **8**	Iron and steel: **6** Process heat, electricity production: **8** Decentral heating: **9**
Ammonia (liquid)		Nitrogen	Haber-Bosch: **11**		Storage at production: **11**	Shipping: **11**	Storage at import: **11**		Conversion to H_2: **4**				
Hydrogen (LOHC)		DBT	Hydrogena-tion: **6-7**		Storage at production: **9**[3)]	Shipping: **11**	Storage at import: **9**[3)]		De-hydro-genation: **6-7**				
Hydrogen (gas)				Compression: **6**		Pipeline: new **9**, refurbished **8**							
Hydrogen (liquid)				Liquefaction: **9**	Storage at production: **8-9**	Shipping: **7**	Storage at import: **8-9**	Re-gasification: **8**[4)]					

- TRL unknown
- TRL 1-6
- TRL 7-8
- TRL 9-10
- TRL 11

1) The TRL at each value chain step only corresponds to the maturity of the main technology and not to the associated technologies of that value chain step; 2) DAC TRL of 6, point-source capture TRL of 11 (point-source TRL: EU technology report, 2019); 3) According to HydroHub HyChain, 2019; 4) According to IRENA; 5) According to Sterner et al, 2019; 6) Shipping TRL refers to tanker transporting relevant renewable energy vector

Source: IEA, IRENA, Desk research

W Renewable methane and hydrogen vectors have comparable landed emissions [kg CO_2e/MWh output]



1) CO_2 for e-methane and methanol synthesis is assumed to be captured as biogenic byproduct in the base case
2) LOHC feedstock emissions are scope 1 instead of scope 2

Source: Roland Berger comprehensive value chain model

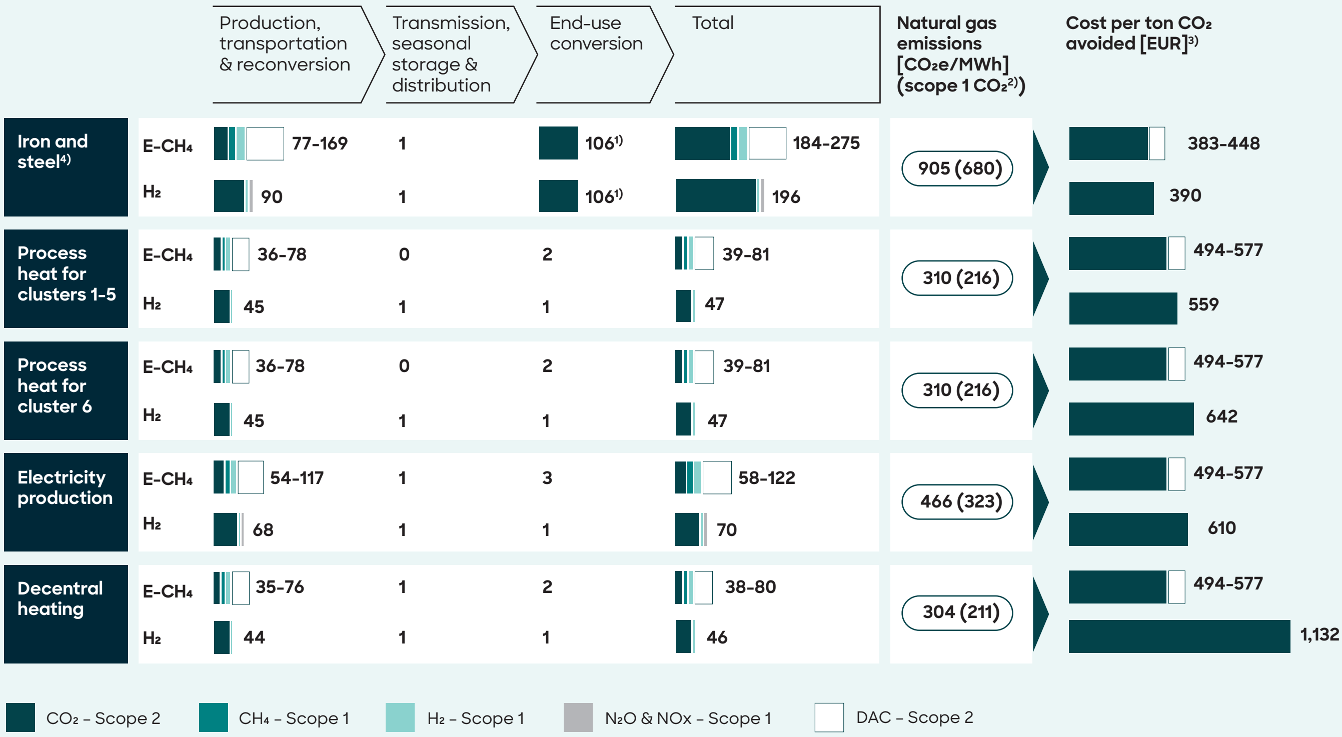
emissions intensity is assumed to be relatively higher in MENA compared to regions such as southern Europe. However, most of these projects are expected to use captive renewable electricity setups in the future, significantly reducing scope 2 emissions and leading to lower overall landed emissions.

For renewable energy vectors to become economically viable, the EU's Emissions Trading System price must exceed EUR 400 per ton CO_2

The total emissions of e-methane and hydrogen delivered via ammonia range from approximately 40 to 120 kg CO_2e/MWh across most use cases, except for iron and steel. ▶ X This represents a more than 70% reduction in GHG emissions for most use cases compared to fossil comparators, meeting the RFNBO requirements[37] even when assuming production in

37 The RED II defines a GHG emission reduction for RFNBOs of 70% below a fossil fuel comparator of 94 gCO_2eq/MJ, i.e. no more than 28.2 gCO_2eq/MJ (equivalent to 102 gCO_2e/kWh H_2)

X The cost per ton CO_2 avoided is higher than EUR 400 for both e-methane and hydrogen [kg CO_2e/MWh output]



1) Emissions due to coal component needed for steel production – These emissions are scope 1 instead of scope 2; 2) Refers to scope 1 CO_2 emissions at end-use conversion per MWh of output; 3) Only includes scope 1 CO_2 emissions at end-use conversion; 4) Values for Iron and steel shown in kg CO_2e/ton steel

Source: Roland Berger comprehensive value chain model

MENA and grid electricity use for processes post-hydrogen production. For iron and steel, emissions range from 200 to 300 kg CO_2e/MWh. However, these emissions include coal emissions, which are excluded from RFNBO requirements, ensuring that the iron and steel use case also meets compliance. While future RFNBO thresholds are expected to become stricter, the anticipated adoption of captive renewable electricity setups will significantly reduce scope 2 emissions, ensuring the continued compliance of e-methane and hydrogen vectors.

The emissions are comparable across use cases due to the limited impact of the downstream value chain steps on the GHG emissions. In large part this is because grid intensity is expected to be lower in the Netherlands by 2040, and leakage plays a smaller role in the downstream steps.

The cost per ton of CO_2 avoided[38] is also comparable for e-methane and renewable hydrogen, except in decentral heating, where the avoidance cost for hydrogen is two times that of e-methane due to the higher cost of energy delivered (the higher cost for decentral heating is primarily driven by the higher cost of energy, as discussed in Chapter 5.) The higher

38 Calculated by dividing the cost difference compared to natural gas by the difference in scope 1 CO_2 emissions during end-use conversion relative to natural gas

avoidance cost implies that the EU's Emissions Trading System (ETS) price would need to be in the EUR 400-600 range to make the business case for renewable vectors competitive.

Of the renewable energy vectors, e-methane is intrinsically a relatively safer vector

The safety characteristics of an energy vector can be determined based on its chemical properties like flammability, explosiveness and toxicity. (E)-methane scores relatively well on these metrics, with a relatively high auto-ignition temperature, narrow explosive range and low toxicity. ▶ Y

In contrast, hydrogen and methanol both present a significantly larger explosiveness bandwidth, which is measured by the explosive range between the lower explosive limit (LEL) and upper explosive limit (UEL), defining the concentrations at which ignition can occur. The explosive ranges are approximately seven and five times wider than (e)-methane, for hydrogen and methanol respectively, making them highly flammable across various air-fuel mixtures. However, it is important to note that hydrogen is much lighter than air, which makes it disperse more rapidly than other molecules. In addition, due to hydrogen's small size, it can escape more easily from indoor environments. Therefore, additional empirical evidence is required to better estimate the risk of hydrogen explosions in practice.

Ammonia has a higher toxicity, as indicated by its low life-threatening limit (*Levens-bedreigende waarde* or LBW) and Acute Exposure Guideline Level (AEGL) scores, meaning

Y Higher explosiveness risk of hydrogen and methanol, coupled with the greater toxicity of ammonia, makes (e)-methane in terms of measures a comparatively safer renewable energy vector

	General		Flammability		Explosiveness		Toxicity			
	Appearance	Odor	Flash point [°C]	Auto-ignition temp. [°C]	LEL [%(V)]	UEL [%(V)]	AEGL 1 [mg/m3]	AEGL 2 [mg/m3]	AEGL 3 [mg/m3]	LBW1) [mg/m3]
(E-) Methane	Colorless gas	Odorless	< -56	670	4.4	17	n/a	n/a	n/a	n/a
Methanol	Colorless liquid	Alcohol-like	9.7	455	5.5	44	690	2,800	9,400	15,000
Ammonia	Colorless gas	Ammonia-like	n/a	651	16	27	21	112	769	780
Hydrogen	Colorless gas	Odorless	n/a	560	4	77	n/a	n/a	n/a	3,300

1) At exposure of 1 hour

Source: Safety data sheets

even minor leaks can pose serious risks. These properties underscore the importance of stringent safety measures for hydrogen, methanol and ammonia handling.

Based on current safety guidelines, hydrogen infrastructure will potentially require additional safety measures compared to (e)-methane

The potential need for additional risk mitigation measures for infrastructure varies across the value chain and depends on legal risk thresholds. Risk is determined by the probability of an adverse event and its potential impact. While these factors are well-established for (e)-methane, limited empirical evidence for hydrogen makes them harder to define. Current regulations adopt a cautious approach with conservative assumptions, potentially leading to additional measures for hydrogen to achieve comparable risk levels to (e)-methane. However, as more data becomes available and understanding improves, regulations may evolve, potentially reducing these requirements.

For instance, a risk that is often considered for handling chemical substances is the site-specific risk *(plaatsgebonden risico)*, defined as the distance from the risk source at which the annual fatality risk is less than one in a million. In case of transportation via pipeline, the site-specific risk is based on the probability of pipeline failure, the probability that after a pipeline failure the released substance will ignite[39] and the impact when the released substance would ignite. While the impact and failure probability are probably comparable for (e)-methane and hydrogen, ignition probabilities differ significantly.

(E)-methane's ignition probability after pipeline failure ranges from 20-80%, depending on pipeline diameter, based on decades of experience. ▶ Z However, with limited data on hydrogen, the RIVM advises assuming a 100% ignition probability for now. This assumption necessitates additional safety measures for hydrogen pipelines if constructed now, to maintain equivalent site-specific risk levels to methane. Measures like increased supervision of digging activities or protective pipeline coverings can mitigate the higher assumed ignition probability. These measures are particularly relevant for smaller pipelines (less than 24-inch diameter) used for last-mile connections, where the ignition probability gap between hydrogen and (e)-methane is more pronounced.

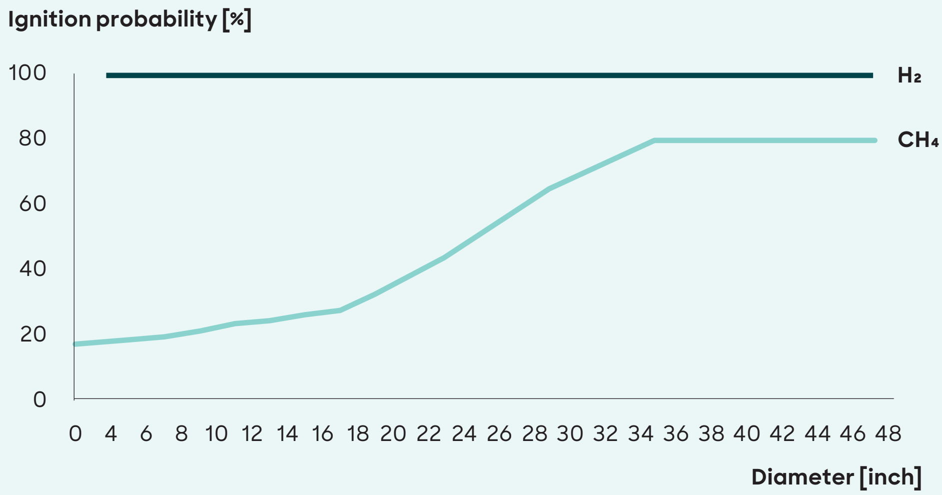
E-methane offers a more land-efficient and logistically manageable alternative to hydrogen

When comparing the land-use requirements of e-methane and hydrogen in the Netherlands,[40] for an equivalent annual energy flow of 100 TWh, e-methane is expected to be notably more land-efficient compared to hydrogen. Within the Netherlands, e-methane

39 Refers to the probability of ignition over a timeframe of 20 to 140 seconds. An equivalent energy amount escaping from a rupture for both hydrogen and methane is assumed

40 This analysis only considers land-use requirements inside the Netherlands. When comparing land-use requirements at the location of production, most of the land is required for renewable electricity generation. When assuming all renewable electricity comes from utility-scale solar PV panels, 100 TWh of hydrogen in the Netherlands would require 1,400 km^2 of land in the production region, compared to 1,600 km^2 for e-methane

Z Based on current RIVM guidelines, hydrogen has a higher probability of ignition after a pipeline rupture than methane, especially for smaller pipelines



Source: RIVM

requires only one-third of the total land use (47 km² vs. 128 km²)[41], covering areas needed for storage at import, seasonal storage, reconversion and end-use conversion. The most substantial land-use difference arises from seasonal storage, where e-methane needs 40 km² compared to hydrogen's 120 km² due to hydrogen's lower volumetric density. Although land requirements for storage at import and reconversion are also lower for e-methane (0.3 km² vs. 1.35 km²)[41], this difference is relatively minor.

In addition, e-methane demands fewer shipping resources. For a 100 TWh annual flow e-methane would require one LNG shipment (transporting an average of 1 TWh per ship) every 3-4 days, while hydrogen (assuming it is shipped via ammonia) would need almost daily shipments, each averaging 0.25 TWh. This increases the logistical intensity for hydrogen. Taken together, these factors make e-methane a more viable option for minimizing land and transportation demands associated with renewable energy use in the Netherlands.

41 Based on publicly available data from Gate Terminal and Port of Rotterdam, along with additional desk research and interviews with industry experts. Estimates for reconversion of hydrogen are based on land use reported by Port of Rotterdam for ammonia cracking

Conclusions & recommendations

E-methane is a feasible and promising renewable energy vector for specific use cases with high downstream costs in the future energy mix of the Netherlands, but its full potential can only be realized with advancement and cost reduction of technologies for renewable hydrogen production, e-methane synthesis and direct air capture

7

As the Netherlands and the broader EU work towards achieving climate neutrality by 2050, e-methane presents itself as a promising and practical energy vector within the renewable energy landscape when also considering the downstream part of the value chain, including transmission, storage, distribution and end-use. The analysis shows that e-methane not only aligns with the Netherlands' climate goals by facilitating the transition from fossil fuels to renewable energy, but also provides several key advantages for specific use cases in terms of cost, emissions, land use and safety. Synthesized from renewable hydrogen and CO_2, e-methane offers the Netherlands an additional feasible and potential option, next to other renewable energy vectors, to achieve net-zero carbon emissions by 2050 in hard-to-electrify use cases, and it does this while supporting decarbonization targets and minimizing the need for extensive new infrastructure.

One of the key benefits of e-methane is its compatibility with existing natural gas infrastructure. As a drop-in replacement for methane, it can make use of the extensive transport, storage and conversion infrastructure that is already in place. This reduces capital expenditures required to scale renewable energy adoption. This infrastructure advantage makes e-methane a particularly cost-competitive renewable energy vector for sectors with high downstream costs, such as decentral heating, industrial process heat for cluster 6 and central dispatchable electricity production. Additionally, certain industrial processes that will require a non-fossil carbon source can benefit from e-methane, as it contains carbon atoms - an advantage over hydrogen or ammonia. In the Netherlands and other similar regions with well-established natural gas networks, e-methane (combined with biomethane) can be deployed rapidly and at a lower cost for certain sectors, placing a much smaller financial and logistical burden on citizens compared to renewable hydrogen.

E-methane's cost-competitiveness in certain use cases is further bolstered by its emissions profile, safety characteristics and efficiency in land use and logistics. The GHG footprint of e-methane is comparable to that of renewable hydrogen vectors, making it a sustainable option for the energy transition. In terms of safety, e-methane is less hazardous than hydrogen and its derivatives and benefits from established safety protocols, whereas hydrogen infrastructure may require additional measures based on current regulations, which are informed by limited operational experience, to achieve comparable risk levels. Additionally, e-methane is more resource-efficient, with significantly lower land and logistical demands than hydrogen. This advantage could be crucial for large-scale deployment, especially in densely populated areas or areas with limited available land. These attributes collectively highlight the societal value of e-methane by reducing the financial burden on society, supporting sustainability goals and enabling a more inclusive transition to renewable energy.

Initially, e-methane could be produced using biogenic CO_2; however, due to feedstock limitations, large-scale adoption will rely on DAC for CO_2 sourcing. While DAC holds promise, uncertainties around its costs present challenges for e-methane's cost-competitiveness in the long term. Sensitivity analyses show that fluctuations in DAC costs could affect the cost of e-methane, making it essential to address these uncertainties through technological advancements and regulatory support. As DAC technology matures, it will be crucial for unlocking e-methane's potential as a large-scale, cost-competitive additional renewable energy vector.

Ultimately, e-methane is a promising renewable energy vector for specific use cases in the Netherlands and other similar regions, where established natural gas infrastructure can be leveraged for renewable energy distribution. Its efficiency in terms of capital and operational costs, emissions, safety, land use and transportation makes it a viable vector in the renewable energy mix. E-methane can play a role in decarbonizing cluster 6, decentral heating and central dispatchable electricity production – sectors where hydrogen adoption seems to face significant challenges.

However, to realize the full potential of e-methane, several key steps should be focused upon:

- **Strategic decarbonization planning**
  Develop specific end-use case strategies that evaluate the true costs of achieving net-zero emissions across the entire value chain *van put tot pit*. Recognize e-methane as a feasible and potential energy vector and integrate it into future energy mix evaluation alongside other renewable vectors.

- **Technological maturity**
  Invest in R&D and pilot/demonstration projects to validate and commercialize e-methane production processes. Demonstration projects can be initiated globally to provide proof of concept and establish scalability and efficiency.

- **Kickstarting e-methane with biogenic CO_2**
  Identify locations (e.g. northern Europe) with high biogenic CO_2 availability to kickstart e-methane production and import.

- **Cost reductions for renewable hydrogen**
  Support initiatives to lower the production costs of renewable hydrogen through innovation in electrolysis technologies, economies of scale and renewable energy price reductions.

- **Scaling DAC solutions for e-methane production**
  Accelerate technological advancements to lower the costs of DAC and ensure economic viability. DAC is critical for scaling up e-methane, especially where biogenic feedstocks are constrained.

- **Utilizing CCS solutions to realize negative emissions**
  Utilizing CCS for high-emission, high-utilization end-use cases powered by e-methane offers the potential to achieve negative emissions. This option should be considered in the overall weighting of the transition paths of end-uses and associated carriers.

- **Leveraging existing gas infrastructure**
  Update and align plans for the existing gas infrastructure to ensure readiness to support e-methane, since e-methane can leverage existing gas infrastructure and

thus reduce the need for significant downstream infrastructure investments. To enable this transition, adequate pipeline capacity must be ensured for e-methane, alongside sufficient infrastructure for other molecules in the future energy mix.

- **Blending-in biomethane and e-methane**
  Implement blending mandates for biomethane and e-methane into natural gas supplies, especially for fragmented CO_2 emission use cases like decentral heating and transport to drive initial market demand.

- **Prioritizing optimal end-use cases**
  Identify and prioritize the most viable end-use cases for e-methane where it offers the highest cost-competitiveness and impact, such as industrial process heat for cluster 6, dispatchable electricity production and decentral heating.

- **Supportive policy and regulatory frameworks**
  Standardize cross-border CO_2 certification to facilitate trade and align regulatory frameworks. Implement supportive policies to attract investment in e-methane and other renewable energy vectors.

- **Public awareness**
  Raise public awareness about the role of renewable gases like e-methane in achieving climate goals to secure societal support for its development and use.

Definition of key terms and abbreviations

Definition of key terms

GHG-neutral CO_2: Refers to CO_2 obtained through DAC or from biogenic sources. CO_2 sourced from fossil sources is excluded

Hydrogen carriers: Molecules containing hydrogen atoms that can facilitate the transportation of hydrogen. Examples include LOHC, methanol and ammonia

Low-carbon energy vectors: Refers to molecules derived from non-renewable sources that meet a GHG emissions reduction threshold of 70% compared to fossil natural gas across the full lifecycle as defined by the EU

Methane carriers: Methane energy vector produced from different sources. Examples include e-methane, biomethane and natural gas

Renewable electricity: Refers to electricity generated from wind, solar (both solar thermal and solar PV), geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas, biogas and nuclear systems. Although nuclear energy is not classified as renewable in the EU, its carbon emissions are very low. Nuclear can thus be used for production of renewable energy vectors if the average emission intensity of the electricity grid is <18 g CO_2e/MJ

Renewable energy vectors: Refers to molecules from organic sources, such as biogas and biomethane, or non-biological renewable sources using electricity (which is at least 90% renewable), such as renewable hydrogen and derivatives like e-methane, renewable ammonia and renewable methanol as defined by the EU

Renewable gaseous molecules: Renewable methane and hydrogen, including green hydrogen, e-methane and biomethane

Abbreviations

AEGL: Acute Exposure Guideline Level
AEGL 1: Mild, reversible effects (discomfort)
AEGL 2: Serious but non-life-threatening effects (disability)
AEGL 3: Disability potentially causing death
CAPEX: Capital expenditure
CH_4: Methane
CH_3OH: Methanol
CO_2: Carbon dioxide
CO_2e: Carbon dioxide equivalent
CCS: Carbon capture and storage
DAC: Direct air capture
DEC scenario: Decentral Initiatives scenario (one of the II3050 report scenarios)
ETS: Emissions Trading System from the EU
EU: European Union
EUR scenario: European Integration scenario (one of the II3050 report scenarios)
GHG: Greenhouse gas
GW: Gigawatt
GWh: Gigawatt hour
H_2: Hydrogen
H_2O: Water
HTL: Main transmission pipelines (hoofdtransportleidingnet)
IA scenario: International Ambition Scenario (one of the EU scenarios – used for 2030 in the II3050 in the report, most similar to the II3050 INT scenario)
IEA: International Energy Agency
II3050: Integrale Infrastructuurverkenning 2030-2050 (Dutch) or Integrated Infrastructure Outlook 2030-2050 (English)
INT scenario: International Trading scenario (one of the II3050 report scenarios)
ISO: International Organization for Standardization
kg: Kilogram
LBW: Life-Threatening Value (Levensbedreigende Waarde)
LEL: Lower explosive limit
LNG: Liquid natural gas
LOHC: Liquid organic hydrogen carrier
MENA: Middle East and North Africa
MW: Megawatt
MWh: Megawatt hour
N_2: Nitrogen
n/a: Not applicable
NAT scenario: National Leadership scenario (one of the II3050 report scenarios)
NH_3: Ammonia
NL: The Netherlands
O_2: Oxygen
OPEX: Operational expenditure
PEM: Proton-exchange membrane
PVs: Photovoltaics
R&D: Research & development
RED: EU Renewable Energy Directive
RFNBO: Renewable fuel of non-biological origin
RTL: Regional transmission pipelines (regionale transportleidingnet)
SOEC: Solid oxide electrolyzer cell
TRL: Technology readiness level
TW: Terawatt
TWh: Terawatt hour
UEL: Upper explosive limit
US: United States
WACC: Weighted average cost of capital

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Feasibility and potential of e-methane in the future energy mix

Appendix

April 2025

Roland Berger

Contents

This document serves as an appendix to the main report ***Feasibility and potential of e-methane in the future energy mix.*** *The document details all the assumptions made and additional analysis carried out* ***during the study***

A. Assumptions

Illustrative

In this section, assumptions used in the model have been detailed, including their source and comfort level

Explanation of the layout of the assumption section

Value chain step

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | End-use conversion

Energy vectors

Category	Parameter	Units	Liquefied Methane Value	Liquefied Methane Source	Ammonia Value	Ammonia Source	Methanol Value	Methanol Source
Stoichiometry	Fuel Consumption	MJ/ton/km	0[1]	Agora[XXIII]	0.05	IEA[XLIV]	0.03[2]	Assumed
	Losses	%	<0.5%	Assumed	0.02%	IEA[XLIV]	0%	HyDelta[XLVI]
	Boiloff Losses	%/day	0.2%	Agora[XXIII]	0.02%	IEA[XLIV]	0%	HyDelta[XLVI]
Asset specifics	CAPEX	EUR/ton	2,834	Agora[XXIII]	1,351	IEA[XLIV]	515	HyDelta[XXXIII]
	OPEX	% of total CAPEX	4%[3]	Agora[XXIII]	4%[3]	Agora[XXIII]	5%[3]	HyDelta[XXXIII]
	Fuel type	-	LNG[4]	Agora[XXIII]	e-NH3	IEA[XLIV]	e-MeOH	Assumed
	Storage tank cap.	kt of carrier	76	Agora[XXIII]	52	IEA[XLIV]	95	HyDelta[XXXIII]
	Lifetime	years	30	Assumed	30	HyDelta[XLVI]	30	HyDelta[XLVI]
	Utilization	% of usage/year	91%	Agora[XXIII]	91%	Agora[XXIII]	91%	Agora[XXIII]
	Speed	km/h	30	Agora[XXIII]	32	IEA[XLIV]	33	HyDelta[XXXIII]
	Suez Canal fee[5]	EUR m	0.9	Assumed	0.7	IRENA[XLVII]	1.1	Assumed
	Port fees[6]	EUR k	<215	Ports[XLVIII][XLIX][L][LI][LII]	<200	Ports[XLVIII][XLIX][L][LI][LII]	<225	Ports[XLVIII][XLIX][L][LI][LII]
Scope 1 Emissions	CO_2, NOx, N_2O	kg of CO_2e/MWh	Corresponding to combustion of LNG/unloading losses		Corresponding to combustion of NH_3		Corresponding to MeOH combustion	
	CH_4	kg of CO_2e/MWh			not applicable		not applicable	
	H_2	kg of CO_2e/MWh	not applicable					

Parameters are categorized based on the vector's stoichiometry, asset-specific characteristics, and associated emissions

Units for each parameters and associated values based on 2040 technology status

Source for each assumption (Latin numerals correspond to exact sources listed at end of the section)

Comfort level on the assumption

High – Applicable to the values of technologies that are currently mature, with substantial supporting data available in public literature

Med-ium – Applicable to the values of technologies with moderate maturity where uncertainty exists about future advancements. In this study, 2040 values are based on optimistic advancements in technology. In some cases, also applicable for values of mature technologies for which sufficient public data is unavailable

Low – Applicable to the values of technologies in the early stages of development, where higher uncertainties exist about future advancements and cost estimates

Overview of the assumptions for all selected renewable energy vectors in 2040

Draft

Assumptions: General

Parameter	Units	Methane [Natural gas] Value	Methane [Natural gas] Source		Hydrogen Value	Hydrogen Source	
kg to ton	[t/kg]	1,000	-	●	1,000	-	●
GJ to kWh	[kWh/GJ]	277.77	-	●	277.77	-	●
MJ to kWh	[kWh/MJ]	0.278	-	●	0.278	-	●
kWh to MJ	[MJ/kWh]	3.6	-	●	3.6	-	●
mmBTU to MWh	[-]	0.29	-	●	0.29	-	●
42-gallon barrel to liter	[liter/42-gallon barrel]	159	-	●	159	-	●
mcf to MWh	[MWh/mcf]	0.29	NRG[I]	●	0.29	NRG[I]	●
m³ to ton	[ton /m³]	0.4	Cetiner[II]	●	-	-	●
Lower heating value (LHV)	[MJ/m³]	35.8 [31.7[1]]	Engineering toolbox[III], TU Delft[IV]	●	-	-	●
Lower heating value (LHV)	[kWh/kg]	13.9 [10.6[1]]	Engineering toolbox[III], TU Delft[IV]	●	33.33	Engineering toolbox[III]	●

Parameter	Units	Ammonia Value	Ammonia Source		Methanol Value	Methanol Source		LOHC Value	LOHC Source	
kg to ton	[t/kg]	1,000	-	●	1,000	-	●	1,000	-	●
GJ to kWh	[kWh/GJ]	277.77	-	●	277.77	-	●	277.77	-	●
MJ to kWh	[kWh/MJ]	0.278	-	●	0.278	-	●	0.278	-	●
kWh to MJ	[MJ/kWh]	3.6	-	●	3.6	-	●	3.6	-	●
mmBTU to MWh	[-]	0.29	-	●	0.29	-	●	0.29	-	●
42-gallon barrel to liter	[liter/42-gallon barrel]	159	-	●	159	-	●	159	-	●
mcf to MWh	[MWh/mcf]	0.29	NRG[I]	●	0.29	NRG[I]	●	0.29	NRG[I]	●
m³ to ton	[ton /m³]	-	-	●	-	-	●	-	-	●
Lower heating value (LHV)	[MJ/m³]	-	-	●	-	-	●	-	-	●
Lower heating value (LHV)	[kWh/kg]	5.2	Engineering toolbox[III]	●	5.5	Engineering toolbox[III]	●	2.0	Deutscher Bundestag[V]	●

Comfort level of the assumption: ● High ● Medium ● Low

1) Based on Groningen/ North-sea gas

Source: NRG, GasTerra, Cetiner, TNO, Engineeringtoolbox, Deutscher Bundestag

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Emissions

		CO_2			CH_4			N_2O			NOx			H2		
Parameter	**Units**	**Value**	**Source**		**Value**	**Source**		**Value**	**Source**		**Value**	**Source**		**Value**	**Source**	
Global Warming Potential for 100 years	[kg of CO_{2e}/kg]	1	-	●	27	IPCC[VI]	●	273	IPCC[VI]	●	8.5	Lammel & Graßl[VII]	●	11.6	Sand et al.[VIII]	●
Emissions from natural gas/methane combustion	[kg/kg]	2.69	US NETL[IX]	●	<0.1	US NETL[IX]	●	<0.1	US NETL[IX]	●	0	US NETL[IX]	●	0	US NETL[IX]	●
Emissions from ammonia combustion	[g/kWh]	0	Zero Carbon Shipping[X]	●	0	Zero Carbon Shipping[X]	●	0.1	Zero Carbon Shipping[X]	●	2.0	Zero Carbon Shipping[X]	●	0.0	Zero Carbon Shipping[X]	●
Emissions from methanol combustion	[g/MJ]	69.0	DNV[XI]	●	0.0	DNV[XI]	●	0.0	DNV[XI]	●	0.4	DNV[XI]	●	0.0	DNV[XI]	●
Emissions from hydrogen combustion	[g/kg]	0.0	EU LCA[XII]	●	0.0	EU LCA[XII]	●	0.0	EU LCA[XII]	●	6.8	EU LCA[XII]	●	0.0	EU LCA[XII]	●

Comfort level of the assumption: ● High ● Medium ● Low

Source: IPCC, Lammel & Graßl (1995), Sand et al. (2023), US NETL, Zero Carbon Shipping, DNV, EU LCA

Draft

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Feedstock

Parameter	Units	US Value	US Source	Middle East Value	Middle East Source	Southern Europe Value	Southern Europe Source	Northern Europe Value	Northern Europe Source
Grid electricity price	[EUR/MWh]	71	EIA[XIII]	41	Assumed	73	VBW[XIV]	58 [NL:92]	VBW[XIV], E-bridge[XV]
Grid intensity	[ton of CO_2/MWh]	0.05	IEA[XVI]	0.21	Enerdata[XVII]	0.03	IEA[XVI]	0.03	IEA[XVI]
Digestion feedstock price	[EUR/ton]	60	CE Delft[XVIII]	60	CE Delft[XVIII]	60	CE Delft[XVIII]	60	CE Delft[XVIII]
CO_2 price from DAC	[EUR/ton]	136	Natuur & Milieu[XIX]	106	Natuur & Milieu[XIX]	138	Natuur & Milieu[XIX]	123	Natuur & Milieu[XIX]
CO_2 price from biogenic byproduct	[EUR/ton]	29	US NETL[XX]	26	US NETL[XX]	30	US NETL[XX]	28	US NETL[XX]
CO_2 price from fossil/ biogenic point source	[EUR/ton]	59	US NETL[XX]	49	US NETL[XX]	59	US NETL[XX]	54	US NETL[XX]
Green Hydrogen production efficiency	[%]	76%	IEA[XXI]	76%	IEA[XXI]	76%	IEA[XXI]	76%	IEA[XXI]
Levelized cost of renewable Hydrogen	[EUR/kg]	2.5	IEA[XXI]	2.5	IEA[XXI]	2.8	IEA[XXI]	3	IEA[XXI]
LOHC (DBT) price	[EUR/kg]	1.6	HySTOC[XXII]	1.6	HySTOC[XXII]	1.6	HySTOC[XXII]	1.6	HySTOC[XXII]

Comfort level of the assumption: High Medium Low

1) We assume the same CO_2 tax for US and Middle East, as CBAM will ensure the carbon price of imports is equivalent to the carbon price of domestic production

Source: IEA, CE Delft, DNV, Enerdata, S&P Global, Natuur & Milieu, HyStoc, EIA, VBW, E-bridge

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Conversion/extraction (1/2)

Value chain steps: **Conversion** | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | End-use conversion

Primary energy production

Category	Parameter	Units	Natural Gas Value	Natural Gas Source	Natural Gas Comfort	E-Methane Value	E-Methane Source	E-Methane Comfort	Biomethane via Anaerobic Digestion Value	Biomethane via Anaerobic Digestion Source	Biomethane Comfort
Stoichiometry	H_2	ton/ton	not applicable			0.50	Agora[XXIII]	High	not applicable		
	CO_2	ton/ton	not applicable			2.69	Agora[XXIII]	High	not applicable		
	N_2	ton/ton	not applicable			not applicable			not applicable		
	Digestion input	ton/ton	not applicable			not applicable			4.12	CE Delft[XVIII]	High
	Electricity	MWh/ton	not applicable			0.05	Agora[XXIII]	High	0.69	CE Delft[XVIII]	High
	Fuel[1]	MWh/ton	0.07	US NETL[IX]	High	not applicable			0.70	CE Delft[XVIII]	High
Asset specifics	CAPEX	EUR m/MW	6.4[2]	EUR/MWh, Canadian Energy Center[XXIV]	High	0.5	IEA[XXV]	Medium	1.5	BIP[XXVI]	High
	OPEX	% of total CAPEX				4%[3]	IEA[XXV]	High	10%	BIP[XXVI]	High
	Lifetime	years	30	Assumed	High	30	IEA[XXVII]	High	25	Navigant[XXVIII]	High
	Utilization	% of 8,760 FLH	95%	Assumed	High	95%	IEA[XXV]	High	95%	Assumed	High
	Capacity	MW	not needed			500	S&P Global[XXIX]	High	8	Engie[XXX]	High
Scope 1 Emissions	CO_2	kg of CO_2e/MWh	12.5	US NETL[IX]	High	0	Assumed	Medium	0	Assumed	High
	CH_4	kg of CO_2e/MWh	29.2	US NETL[IX]	High	0	EU LCA[XII]	Medium	10	IEA Bioenergy[XXXII]	High
	N_2O	kg of CO_2e/MWh	<0.01	US NETL[IX]	High	not applicable			0	Assumed	High
	NO_x	kg of CO_2e/MWh	not applicable			not applicable			not applicable		
	H_2	kg of CO_2e/MWh	not applicable			7.5	Navajas et al.[XXXI]	High	not applicable		

1) Figure depicts combustion of the respective energy vector in the production step; 2) Number incorporate producing, under development and discovery phases of natural gas production; 3) Figure only covers fixed OPEX, excl. feedstock prices;
Source: US NETL, Canadian Energy Center, Exxon Mobile, IEA, CE Delft

Comfort level of the assumption: High Medium Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Conversion/extraction (2/2)

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | End-use conversion

Category	Parameter	Units	Ammonia Value	Ammonia Source	Methanol Value	Methanol Source	LOHC (DBT) Value	LOHC (DBT) Source
Stoichiometry	H_2	ton/ton	0.18	Agora[XXIII]	0.20	HyDelta[XXXIII]	0.06	HySTOC[XXII]
	CO_2	ton/ton		not applicable	0.07	HyDelta[XXXIII]		not applicable
	N_2	ton/ton	0.82	Agora[XXIII]		not applicable		not applicable
	DBT-HO	ton/ton		not applicable		not applicable	0.94	EU LCA[XII]
	Electricity	MWh/ton	0.65[1]	IRENA[XXXIV]	0.20	HyDelta[XXXIII]	0.02	EU LCA[XII]
	Fuel[2]	MWh/ton		not applicable		not applicable		not applicable
Asset specifics	CAPEX	EUR/ton	283	IRENA[XXXIV]	158	HyDelta[XXXIII]	21	IRENA[XXXIV]
	OPEX[3]	% of total CAPEX	3%	IRENA[XXXIV]	2.7%	HyDelta[XXXIII]	1.5%	HySTOC[XXII]
	Lifetime	years	30	Assumed	30	Assumed	30	Assumed
	Utilization	% of 8,760 FLH	95 %	Assumed	95%	Assumed	95%	Assumed
	Capactiy	kt/year	1,825	IRENA[XXXIV]	475	Hydelta[XXXIII]	329	IRENA[XXXIV]
Scope 1 Emissions	CO_2	kg of CO_2e/MWh		not applicable	0	Assumed		not applicable
	CH_4	kg of CO_2e/MWh		not applicable		not applicable		not applicable
	N_2O	kg of CO_2e/MWh		not applicable		not applicable		not applicable
	NO_x	kg of CO_2e/MWh	1.6	EU LCA[XII]		not applicable		not applicable
	H_2	kg of CO_2e/MWh	1.7	EU LCA[XII]	0.4	EU LCA[XII]	0.36	EU LCA[XII]

1) Electricity consumption includes nitrogen separation from air; 2) Figure depicts combustion of the respective energy vector in the production step; 3) Figure only covers fixed OPEX, excl. feedstock prices

Source: EU LCA, HyDelta, HySTOC

Comfort level of the assumption: High Medium Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Preparing for transport

Value chain steps: Conversion → **Preparing for transport** → Storage at export loc. → Transport-ation → Storage at import loc. → Gasification → Re-conversion → Transmission → Seasonal storage → Distribution → End-use conversion

Category	Parameter	Units	E-Methane[1] compression: Value	E-Methane[1] compression: Source	E-Methane[1] liquefaction: Value	E-Methane[1] liquefaction: Source	Hydrogen compression: Value	Hydrogen compression: Source	Hydrogen liquefaction: Value	Hydrogen liquefaction: Source
Stoichiometry	Electricity input	MWh/ton	0.28	Sterner et al.[XXXV)]	0.48	Agora[XXIII)]	0.52	HyDelta[XXXIII)]	6.0	IRENA[XXXIV)]
	Losses	%	0.15%	US NETL[IX)]	0.1%	Agora[XXIII)]	0.5%	HyDelta[XXXIII)]	2%	EU LCA[XII)]
Asset specifics	CAPEX	EUR/ton	0.1	EUR/MWh, Oxford Inst.[XXXVI)]	750	Zhang et al.[XXXVII)]	180	HyDelta[XXXIII)]	2,915	IRENA[XXXIV)]
	OPEX	% of total CAPEX			2.5%[2)]	Oxford Inst.[XXXVI)]	4%[2)]	HyDelta[XXXIII)]	4%[2)]	Agora[XXIII)]
	Lifetime	years	15	Assumed	30	Appea[XXXVIII)]	15	HyDelta[XXXIII)]	30	Assumed
	Utilization	% of 8,760 FLH	85%	Assumed	95%	Assumed	85%	HyDelta[XXXIII)]	95%	HyDelta[XXXIII)]
	Capacity	kt	not needed		32,000	Zhang et al.[XXXVII)]	14	HyDelta[XXXIII)]	73	IRENA[XXXIV)]
Scope 1 Emissions	CO_2	kg of CO_2e/MWh	not applicable[3)]		not applicable[3)]		not applicable		not applicable	
	CH_4	kg of CO_2e/MWh	Corresponding to losses		Corresponding to losses					
	N_2O	kg of CO_2e/MWh	not applicable		not applicable					
	NO_x	kg of CO_2e/MWh								
	H_2	kg of CO_2e/MWh					Corresponding to losses		Corresponding to losses	

1) Input also valid for biomethane and fossil natural gas; 2) Value only comprises fixed OPEX, excl. feedstock costs; 3) Conversion process step is electrified and therefore only scope 2 emissions are considered

Source: EU Store & Go, US NETL, Oxford Institute, Agora Energiewende, HyDelta

Comfort level of the assumption: High Medium Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Local Storage (1/2)

Value chain steps: Conversion › Preparing for transport › **Storage at export loc.** › Transportation › **Storage at import loc.** › Gasification › Re-conversion › Transmission › Seasonal storage › Distribution › End-use conversion

Category	Parameter	Units	Liquefied Methane[1] Value	Liquefied Methane[1] Source		Ammonia Value	Ammonia Source		Methanol Value	Methanol Source	
Stoichiometry	Electricity input	MWh/ton	1.21	MWh/kg of boiloff, Li & Wen[XXXIX)]	High	0.03	Llyod' s Register[XL)]	Medium	0	EU LCA[XII)]	Medium
	Losses	%	0%[2)]	EU LCA[XII)]	Medium	0.02%	EU LCA[XII)]	Medium	0%	EU LCA[XII)]	Medium
Asset specifics	CAPEX	EUR/ton	0.05	EUR/MWh/day, Fluxys[XLI)]	High	909	HyDelta[XXXIII)]	High	473	HyDelta[XXXIII)]	High
	OPEX	% of total CAPEX				2.0%[3)]	HyDelta[XXXIII)]	High	0.7%[3)]	HyDelta[XXXIII)]	High
	Lifetime	years	40	Fluxys[XLII)]	High	30	Assumed	High	30	HyDelta[XXXIII)]	High
	Utilization	% of 8,760 FLH	98%	Assumed	High	98%	Assumed	High	98%	Assumed	High
	Capacity	kt	265	Fluxys[XLIII)]	High	55	HyDelta[XXXIII)]	High	32	HyDelta[XXXIII)]	High
	Storage Length	days	Duration of sea transport one-way		High	Duration of sea transport one-way		High	Duration of sea transport one-way		High
Scope 1 Emissions	CO_2	kg of CO_2e/MWh	not appliable			not applicable			not applicable		
	CH_4	kg of CO_2e/MWh	0	EU LCA[XII)]	Medium						
	N_2O	kg of CO_2e/MWh	not appliable								
	NO_x	kg of CO_2e/MWh									
	H_2	kg of CO_2e/MWh									

1) Input also valid for biomethane and fossil natural gas; 2) Boiloff losses (-0.07 %/day) are assumed to be reliquefied; 3) Figures only comprises fixed OPEX excl. feedstock costs

Source: CE Delft, Fluxys, EU LCA, HyDelta

Comfort level of the assumption: High Medium Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Local Storage (2/2)

Value chain steps: Conversion | Preparing for transport | **Storage at export loc.** | Transport-ation | **Storage at import loc.** | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | End-use conversion

Category	Parameter	Units	LOHC Value	LOHC Source	LOHC Comfort	Liquid H_2 Value	Liquid H_2 Source	Liquid H_2 Comfort
Stoichiometry	Electricity input	MWh/ton	0	EU LCA[XII)]	High	0.15	HyDelta[XXXIII)], IEA[XLIV)]	Medium
	Losses	%/day	0%	EU LCA[XII)]	High	0%[1)]	IRENA[XXXIV)]	Medium
Plant specifics	CAPEX	EUR/ton	322	Ortiz Cebolla et al.[XLV)]	Medium	13,650	IRENA[XXXIV)]	Medium
	OPEX	% of total CAPEX	1.0%[2)]	Ortiz Cebolla et al.[XLV)]	Medium	2.0%[2)]	HyDelta[XXXIII)]	High
	Lifetime	years	30	HyDelta[XXXIII)]	High	30	HyDelta[XXXIII)]	High
	Utilization	% of 8,760 FLH	98%	HyDelta[XXXIII)]	High	98%	Assumed	High
	Capacity	kt	30	Ortiz Cebolla et al.[XLV)]	High	7	HyDelta[XXXIII)]	High
	Storage Length	days	Duration of sea transport one-way		High	Duration of sea transport one-way		High
Scope 1 Emissions	CO_2	kg of CO_2e/MWh	not applicable			not applicable		
	CH_4	kg of CO_2e/MWh	not applicable			not applicable		
	N_2O	kg of CO_2e/MWh	not applicable			not applicable		
	NO_x	kg of CO_2e/MWh	not applicable			not applicable		
	H_2	kg of CO_2e/MWh	not applicable			Corresponding to losses in storage		

1) Boiloff losses (~0.1 %/day) is assumed to be reliquefied, requiring 0.15 kWh per kg of boiloff gas; 2) Value only comprises fixed OPEX, excl. feedstock costs

Source: CE Delft, Fluxys, HyDelta

Comfort level of the assumption: High, Medium, Low

Draft

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Maritime transport (1/2)

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | **Transport-ation** | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | End-use conversion

Category	Parameter	Units	Liquefied Methane		Ammonia		Methanol	
			Value	Source	Value	Source	Value	Source
Stoichiometry	Fuel Consumption	MJ/ton/km	0[1)]	Agora[XXIII)]	0.05	IEA[XLIV)]	0.03[2)]	Assumed
	Losses	%	<0.5%	Assumed	0.02%	IEA[XLIV)]	0%	HyDelta[XLVI)]
	Boiloff Losses	%/day	0.2%	Agora[XXIII)]	0.02%	IEA[XLIV)]	0%	HyDelta[XLVI)]
Asset specifics	CAPEX	EUR/ton	2,834	Agora[XXIII)]	1,351	IEA[XLIV)]	515	HyDelta[XXXIII)]
	OPEX	% of total CAPEX	4%[3)]	Agora[XXIII)]	4%[3)]	Agora[XXIII)]	5%[3)]	HyDelta[XXXIII)]
	Fuel type	-	LNG[4)]	Agora[XXIII)]	e-NH3	IEA[XLIV)]	e-MeOH	Assumed
	Storage tank cap.	kt of vector	76	Agora[XXIII)]	52	IEA[XLIV)]	95	HyDelta[XXXIII)]
	Lifetime	years	30	Assumed	30	HyDelta[XLVI)]	30	HyDelta[XLVI)]
	Utilization	% of usage/year	91%	Agora[XXIII)]	91%	Agora[XXIII)]	91%	Agora[XXIII)]
	Speed	km/h	30	Agora[XXIII)]	32	IEA[XLIV)]	33	HyDelta[XXXIII)]
	Suez Canal fee[5)]	EUR m	0.9	Assumed	0.7	IRENA[XLVII)]	1.1	Assumed
	Port fees[6)]	EUR k	<215	Ports[XLVIII)XLIX)L)LI)LII)]	<200	Ports[XLVIII)XLIX)L)LI)LII)]	<225	Ports[XLVIII)XLIX)L)LI)LII)]
Scope 1 Emissions	CO_2, NOx, N_2O	kg of CO_2e/MWh	Corresponding to combustion of LNG/unloading losses		Corresponding to combustion of NH_3		Corresponding to MeOH combustion	
	CH_4	kg of CO_2e/MWh			not applicable		not applicable	
	H_2	kg of CO_2e/MWh	not applicable					

1) LNG carrier runs on boiloff losses; 2) Methanol vessels assumed to have identical fuel consumption in MJ/ton as ammonia vessels; 3) Value only comprises fixed OPEX, excl. feedstock costs; 4) CO_2 emissions only accounted for natural gas, as emissions from e-methane or biomethane are net zero; 5) Tariff for roundtrip through Suez canal on MENA route scales by weight of cargo; 6) Port fees of import (Rotterdam) and export port (US: Corpus Christi, MENA: Abu Dhabi, ESP: Huelva, NOR: Greenland)

Source: Oxford Institute for Energy Studies, HyDelta, EU LCA, DNV, ZeroCarbon Shipping

Comfort level of the assumption: High Medium Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Maritime transport (2/2)

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | **Transport-ation** | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | End-use conversion

Category	Parameter	Units	LOHC Value	LOHC Source	Liquid H_2 Value	Liquid H_2 Source
Stoichiometry	Fuel Consumption	MJ/ton/km	0.03[1]	Assumed	0[2]	IEA[XLIV]
	Losses	%	0%	HyDelta[XLVI]	1%	IEA[XLIV]
	Boiloff Losses	%/day	0%	HyDelta[XLVI]	0.6%	IEA[XLIV]
Asset specifics	CAPEX	EUR/ton	471	HyDelta[XXXIII]	40,196	IEA[XLIV]
	OPEX	% of total CAPEX	6%[3]	HyDelta[XXXIII]	4%[3]	Agora[XXIII]
	Fuel type	-	e-MeOH	Assumed	Liquid H_2	IEA[XLIV]
	Storage tank cap.	kt of vector	104	HyDelta[XXXIII]	10	IEA[XLIV]
	Lifetime	years	30	HyDelta[XLVI]	30	HyDelta[XLVI]
	Utilization	% of usage/year	91%	Agora[XXIII]	91%	Agora[XXIII]
	Speed	km/h	33	HyDelta[XXXIII]	30	IEA[XLIV]
	Suez Canal fee[4]	EUR m	1.2	Assumed	0.1	Assumed
	Port fees[5]	EUR k	<230	Ports[XLVIII][XLIX][L][LI][LII]	<190	Ports[XLVIII][XLIX][L][LI][LII]
Scope 1 Emissions	CO_2, NOx, N_2O	kg of CO_2e/MWh	Corresponding to MeOH combustion[1]		Corresponding to combustion of LH_2	
	CH_4	kg of CO_2e/MWh	not applicable		not applicable	
	H_2	kg of CO_2e/MWh	not applicable		Corresponding to losses of loading	

1) LOHC vessels assumed to use methanol as fuel and have identical fuel consumption in MJ/ton as ammonia vessels; 2) Liquid H_2 carrier runs entirely on boiloff losses; 3) Value only comprises fixed OPEX, excl. feedstock costs; 4) Tariff for a roundtrip through the Suez canal on the MENA route scales by weight of cargo; 5) Port fees of import (Rotterdam) and export port (US: Corpus Christi, MENA: Abu Dhabi, ESP: Huelva, NOR: Greenland)

Source: Oxford Institute for Energy Studies, HyDelta, EU LCA, Zero Carbon Shipping

Comfort level of the assumption: High Medium Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Pipeline Transportation

Value chain steps: Conversion → Preparing for transport → Storage at export loc. → **Transport-ation** → Storage at import loc. → Gasification → Re-conversion → Transmission → Seasonal storage → Distribution → End-use conversion

Category	Parameter	Units	Compressed methane Value	Compressed methane Source	Comfort	Compressed hydrogen Value	Compressed hydrogen Source	Comfort
Stoichiometry	Electricity input	kWh/ton/km	0.08	EU LCA[XII]	High	0.6	Agora[XXIII]	High
	Losses	%/1,000 km	0.02%	EU LCA[XII]	High	0.40%[1]	EU LCA[XII]	Medium
Plant specifics	Existing tariff [NOR]	EUR/MWh	10[2]	Bottom-up calculation	Medium	not applicable		
	Existing tariff [ESP]	EUR/MWh	10[3]	Bottom-up calculation	Medium	not applicable		
	New tariff	EUR/MWh/1000 km	3.9[4]	Assumed	Medium	6.0	IEA[LIII]	Medium
	Lifetime	years	55	Assumed	High	55	Assumed	High
	Utilization	%	70%[5]	Calculated	High	90%[5]	Calculated	High
	Pipeline length [NOR]	km	~2,300	Assumed	High	~ 2,300	Assumed	High
	Pipeline length [ESP]	km	~2,300	Assumed	High	~ 2,300	Assumed	High
	Max. capacity	GW	18.8	Assumed	High	16.9	IEA[LIII]	High
Scope 1 Emissions	CO_2	kg of CO_2e/MWh	not applicable			not applicable		
	CH_4	kg of CO_2e/MWh	Corresponding to losses in pipeline			not applicable		
	N_2O	kg of CO_2e/MWh	not applicable			not applicable		
	NO_x	kg of CO_2e/MWh	not applicable			not applicable		
	H_2	kg of CO_2e/MWh	not applicable			Corresponding to losses in pipeline		

1) Considering total loss of 1% and then dividing by 2.5 to get the loss in %/1,000 km; 2) Pipeline length form NOR and ESP is similar; 3) Tariff assumes transmission from Spain via France and Belgium; 4) NG pipeline cost are assumed by scaling hydrogen pipeline LCOH by 65% to account for fact that CAPEX of NG pipeline is 30-40% cheaper and can carry 10% more volume; 5) Utilization is scaled for the total expected demand by 2040

Source: HyDelta, EU LCA, Fluxys, IEA

Comfort level of the assumption: High, Medium, Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Gasification

Value chain steps: Conversion – Preparing for transport – Storage at export loc. – Transport-ation – Storage at import loc. – **Gasification** – Re-conversion – Transmission – Seasonal storage – Distribution – End-use conversion

Category	Parameter	Units	Liquified Methane to Gas: Value	Liquified Methane to Gas: Source	Comfort	Liquified Hydrogen to Gas: Value	Liquified Hydrogen to Gas: Source	Comfort
Stoichiometry	Electricity	MWh/ton	0.06	EU LCA[XII)]	High	0.2	IRENA[XXXIV)]	High
	Electricity price	EUR/MWh	92	E-bridge[XV)]	High	92	E-bridge[XV)]	High
	Losses	%	0.01%	EU LCA[XII)]	High	0.01%	Assumed	High
Asset specifics	CAPEX	EUR/ton	200	Frontier[LIV)]	High	441	IRENA[XXXIV)]	Medium
	OPEX	% of total CAPEX.	2.5%	Assumed	High	4%[1)]	Brändle et al.[LV)]	High
	Lifetime	years	30	Assumed	High	30	Assumed	High
	Utilization	% of 8,760 FLH	95%	Assumed	High	95%	Assumed	High
	Capacity	kt/year	174	TWh, Fluxys[XLIII)]	High	912	IRENA[XXXIV)]	Medium
Scope 1 Emissions	CO_2	kg of CO_2e/MWh	not applicable			not applicable		
	CH_4	kg of CO_2e/MWh	Corresponding to losses in pipeline			not applicable		
	N_2O	kg of CO_2e/MWh	not applicable			not applicable		
	NO_x	kg of CO_2e/MWh	not applicable			not applicable		
	H_2	kg of CO_2e/MWh	not applicable			Corresponding to losses in pipeline		

1) Value only comprises fixed OPEX, excl. feedstock costs

Source: Oxford Institute for Energy Studies, HyDelta, EU LCA

Comfort level of the assumption: High Medium Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Reconversion

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | **Re-conversion** | Transmission | Seasonal storage | Distribution | End-use conversion

Category	Parameter	Units	Methane to H2 (SMR) Value	Methane to H2 (SMR) Source	Comfort	Ammonia to Hydrogen Value	Ammonia to Hydrogen Source	Comfort	Methanol to Hydrogen Value	Methanol to Hydrogen Source	Comfort	LOHC (DBT to H_2) Value	LOHC (DBT to H_2) Source	Comfort
Stoichiometry	**Energy vector**	ton/ton	1.32	IEA[XLIV]	High	7.2	HyDelta[XLVI]	High	7.1	EU LCA[XII]	High	22.4[1]	Assumed	High
	Electricity	MWh/ton	0[2]	EU LCA[XII]	High	0.99[3]	HyDelta[XLVI]	Medium	1.3[2,3]	EU LCA[XII]	Medium	1.9[3]	EU LCA[XII]	Medium
	Electricity price	EUR/MWh	95	E-bridge[XV]	High	95	E-bridge[XV]	High	95	E-bridge[XV]	High	95	E-bridge[XV]	High
Asset specifics	**CAPEX**	EUR/ton	655	EUR/kW, IEA[XLIV]	High	1,041	HyDelta[XLVI]	Medium	455	Agora[XXIII]	Medium	769	IRENA[XXXIV]	Medium
	OPEX	% of total CAPEX.	5%[4]	IEA[XLIV]	High	3%[4]	IEA[XLIV]	High	3%[4]	HyDelta[XXXIII]	High	2.5%[4]	HySTOC[XXII]	High
	Lifetime	years	25	Assumed	High	25	IEA[XXVII]	High	25	Assumed	High	25	Assumed	High
	Utilization	% of 8,760 FLH	90%	Assumed	High	90%	Assumed	High	90%	HyDelta[XXXIII]	High	90%	Assumed	High
	Capacity	kt/year	75	HyDelta[XLVI]	High	270	HyDelta[XLVI]	High	183	Agora[XXII]	High	225	IRENA[XXXIV]	High
Scope 1 Emissions	**CO_2**	kg of CO_2e/MWh	270[5]	EU LCA[XII]	High	not applicable			0[6]	EU LCA[XII]	High	not applicable		
	CH_4	kg of CO_2e/MWh	not applicable			not applicable			not applicable			not applicable		
	N_2O	kg of CO_2e/MWh	not applicable			<0.01	EU LCA[XII]	High	not applicable			not applicable		
	NO_x	kg of CO_2e/MWh	not applicable			0.5	EU LCA[XII]	High	not applicable			1.1	EU LCA[XII]	High
	H_2	kg of CO_2e/MWh	not applicable			0	EU LCA[XII]	High	0.04	EU LCA[XII]	High	<0.01	EU LCA[XII]	High

1) In addition to the required input of DBT (16.3 ton/ton of H2), DBT is combusted to provide heat for the reconversion; 2) Methane is combusted for the process heat and therefore no additional energy input is required; 3) Value includes compression of H_2 to 80 bar; 4) Value only comprises fixed OPEX, excl. feedstock costs; 5) Emissions are net zero for e-methane and biomethane; 6) Emissions are net zero and therefore not considered

Source: Oxford Institute for Energy Studies, HyDelta, EU LCA

Comfort level of the assumption: High | Medium | Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Transmission

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | **Transmission** | Seasonal storage | Distribution | End-use conversion

Category	Parameter	Units	e-Methane/Biomethane Value	e-Methane/Biomethane Source	Comfort	Hydrogen Value	Hydrogen Source	Comfort
Stoichiometry	Electricity input	kWh/ton/km	0.08	EU LCA[XII]	High	0.6	Agora[XXIII]	Medium
	Losses	%/1,000 km	0.02%	EU LCA[XII]	High	0.04%[1]	EU LCA[XII]	Medium
Plant specifics	Tariff	EUR/MWh	1.6[2]	Bottom-up calculation	Medium	1.7	Bottom-up calculation	Medium
	Lifetime	years	55	Assumed	High	55	Assumed	High
	Utilization	% of 8760 FLH	90%	Assumed	High	90%	Assumed	High
	Capacity input	TWh	359[4]	Assumed, II3050[LVI]	Medium	137	II3050[LVI]	High
	Average distance per end-user	km	250	Assumed	Medium	250	Assumed	Medium
Scope 1 Emissions	CO_2	kg of CO_2e/MWh	not applicable			not applicable		
	CH_4	kg of CO_2e/MWh	Corresponding to losses in pipeline			not applicable		
	N_2O	kg of CO_2e/MWh	not applicable			not applicable		
	NO_x	kg of CO_2e/MWh	not applicable			not applicable		
	H_2	kg of CO_2e/MWh	not applicable			Corresponding to losses in pipeline		

As cluster 6 and power plants will require a dedicated pipeline they will pay an additional cost to this tariff:
- Process heat cluster 6: EUR/MWh 16
- Electricity production: EUR/MWh 1.4

1) Considering total loss of 1% and then dividing by 2.5 to get the loss in %/1,000 km; 2) Tariff is the mean of the past five years of annual revenues of Gasunie Transport Services divided by the annual gas supply in the respective year and scaled by a factor of 2.5 to account for reduction in demand; 3) Combination of HTL and RTL pipelines; 4) Includes demand from e-methane and natural gas and demand for export
Source: HyDelta, EU LCA, Fluxys

Comfort level of the assumption: High, Medium, Low

Draft

Backup on the assumptions for transmission pipeline tariffs in 2040

Transmission tariff calculation – 2024, 2030 and 2040

Parameters	Gas network - 2024	Gas network - 2040	H2-backbone - 2030	H2-backbone - 2040
Capex new [EUR m/km]	Not applicable	Not applicable	3.7	3.7
Capex refurbished [EUR m/km]			0.99	0.99
Refurbished pipeline [%]			70%	70%
Pipeline length [km]	11,256	11,256	1100	1600
Total CAPEX [EUR m]	4584	3670[1)]	1,997	3,865
Lifetime [y]	55	55	55	55
WACC [%]	4%	4%	4%	4%
Opex [% of Capex]	10%	10%	2.1% (1% of new value of pipelines)	1.5% (1% of new value of pipelines)
TOTEX [EUR m/y]	796	581	160	286
Power [GW]	Not applicable	Not applicable	Not applicable	Not applicable
Volume [TWh]	700	359[2)]	78	136
Tariff [EUR/MWh]	**1.1**	**1.6**	**2.0**	**1.7**

Key assumptions

- CAPEX for hydrogen pipelines is based on HyWay27 and adjusted with inflation percentage of 5.3% year on year between 2021-2024[3)]
- Assuming 30% of the backbone will be new pipelines and 70% will be refurbished pipelines in 2030
- The hydrogen backbone is assumed to be 1100 km in 2030 and 500 km is added to backbone in 2040 to account for additional volume needed
- OPEX for hydrogen backbone is assumed to be 1% of the new value of the backbone

1) Estimated by adding the expected investments to the current book value and subtracting the expected depreciation costs; 2) Includes methane demand for export; 3) HyWay27 estimated the capex per km for the hydrogen backbone in a report published in 2021, we account for the value increase since
Source: HyWay27, GTS annual reports, IRENA, Liander, HyRegions, Netbeheer Nederland, II3050

Backup on the assumptions for transmission pipeline tariffs in 2040

Additional pipeline CAPEX for electricity production & process heat cluster 6 - 2040

Parameters	Electricity production: Hydrogen	Electricity production: Methane	Process heat for cluster 6: Hydrogen	Process heat for cluster 6: Methane
Capex new [EUR m/km]	1.9	Assumed to be directly connected to the main transmission grid	2.5	Assumed to be directly connected to the main transmission grid
Capex refurbished [EUR m/km]	0.5		1.25	
New pipeline [%]	50%		50%	
Pipeline length [km]	150		400	
Total CAPEX [EUR m]	177		750	
Lifetime [years]	55		55	
WACC [%]	8%		8%	
OPEX [% of CAPEX]	1.6%		1.3%	
TOTEX [EUR m/year]	13		54	
Volume [TWh]	14		5	
Tariff for H_2 [EUR/MWh]	**1.4**		**16**	

Based on pipeline with 20-30 cm diameter multiplied by scaling factor of 2.5

Key assumptions

- Power plants and industrial facilities in cluster 6 will require dedicated pipelines to connect to the hydrogen backbone
- The additional CAPEX is accounted via an added tariff
- WACC of 8% is assumed as cost of capital will be higher for private players compared to GTS
- In electricity production, pipeline diameter is assumed to be 50% of the diameter of the H_2 backbone pipeline resulting in 50% of the H_2 backbone CAPEX
- In cluster 6 industry, a factor of 2-3 to the original Capex numbers is applied to account for additional complexities and safety adherences in the placing of the pipelines
- Length of additional pipeline required is based on the HyRegions report
  - In electricity production 9 power plants are not directly connected to the backbone, also based on the HyRegions report

Source: HyRegions, HyWay27, IRENA, II3050

Draft

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Seasonal storage

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | **Seasonal storage** | Distribution | End-use conversion

Category	Parameter	Units	e-Methane/Biomethane Value	e-Methane/Biomethane Source	Hydrogen Value	Hydrogen Source
Stoichiometry	Electricity input	MWh/MWh	0.02	Assumed (Medium)	0.03	HyDelta[XXXIII)] (Medium)
	Losses	%/day	0.02%	Assumed (Medium)	0.04%	IEA[LVII)] (Medium)
Plant specifics	Depleted gas field tariff	EUR/MWh	10	Bottom-up calculation (High)	36	Bottom-up calculation (High)
	Salt cavern tariff	EUR/MWh	15	Bottom-up calculation (High)	51	Bottom-up calculation (High)
	Share of gas sent to storage	% of total gas				
Scope 1 Emissions	CH_4	kg of CO_{2e}/MWh	Corresponding to losses		not applicable	
	H_2	kg of CO_{2e}/MWh	not applicable		Corresponding to losses	

Different share of gas sent to storage assumed per use case:

- Iron & steel 5-15%
- Process heat cluster 1-5 5-15%
- Process heat cluster 6 5-15%
- Electricity production 25-35%
- Decentral heating 35-45%

1) Number only covers fixed OPEX, excl. feedstock costs

Source: IEA, HyDelta, Fluxys

Comfort level of the assumption: High Medium Low

Backup on the assumptions for seasonal storage tariffs in 2040

Seasonal storage tariff calculation for hydrogen and e-methane[1)]

	Depleted gas field		Salt cavern	
	H_2	E-CH_4	H_2	E-CH_4
Working gas volume [bcm]	0.78	0.78	0.08	0.08
Cushion gas volume [bcm]	2.00	2.00	0.06	0.06
Lease rate [EUR m/year]	10	10	*not applicable*	
Storage CAPEX [EUR m]	*no additional investment needed*		60	60
Cushion gas CAPEX [EUR m]	540	693	17	22
Compression CAPEX [EUR m]	11.9	4.0	10.0	3.3
Wells/piping CAPEX [EUR m]	4.4	4.4	3.2	3.2
Gas cleaning CAPEX [EUR m]	30.7	*Assuming no gas cleaning required*		
OPEX [EUR m / year]	16.3	12.5	1.6	2.0
Lifetime [years]	30	30	30	30
WACC [%]	8%	8%	8%	8%
LCOS [EUR/MWh]	**35**	**10**	**51**	**15**

Key assumptions

- Assuming H_2 price of 3 EUR/kg and CH_4 price of 30 EUR/MWh
- A mix of green and blue hydrogen is used as cushion gas for hydrogen storage and natural gas is used as cushion gas for e-methane storage
- CAPEX for methane compressors assumed to be one third of CAPEX for hydrogen compressors
- No cleaning assumed for e-methane in depleted gas fields or for e-methane or hydrogen in salt caverns
- Salt caverns assumed to have 2 cycles/year

1) Taking half the H_2 and CH_4 price would lead to tariffs of 22.3 and 6.1 EUR/MWh for H_2 and e-CH_4 storage resp. in depleted gas fields & 41.6 and 11.4 EUR/MWh for H_2 and e-CH_4 storage resp. in salt caverns

Source: TNO, HyDelta, EWI, Desk research

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Distribution – Iron & steel

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | **Distribution** | End-use conversion

As Tata Steel is expected to be directly connected to backbone there would be no additional last mile cost

Comfort level of the assumption: High Medium Low

Draft

Draft

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: End-use conversion – Iron & steel

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | **End-use conversion**

Category	Parameter	Units	e-Methane/Biomethane Value	e-Methane/Biomethane Source	Comfort	Hydrogen Value	Hydrogen Source	Comfort
Stoichiometry	Methane	MWh/ton steel	2.4	TSN[LVIII], Agora[XXIII]	High	not applicable		
	Hydrogen	MWh/ton steel	not applicable			2.2	TSN[LVIII], Agora[XXIII]	High
	Electricity	MWh/ton steel	0.8	TSN[LVIII], Agora[XXIII]	High	0.8	TSN[LVIII], Agora[XXIII]	High
	Coal	ton/ton steel	0.03	TSN[LVIII], Agora[XXIII]	High	0.03	TSN[LVIII], Agora[XXIII]	High
Plant specifics	CAPEX	EUR/ton steel	750[1]	DIW[LIX]	High	750[1]	DIW[LIX]	High
	Demand	TWh/year	14	II3050[LVI]	High	14	II3050[LVI]	High
	Other plant specific financials not considered[2]							
Scope 1 Emissions	CO_2	kg of CO_2e/ton steel	80[2]	Climate accountability[LX]	High	80	Climate accountability[LX]	High
	CH_4	kg of CO_2e/ton steel	not applicable			not applicable		
	N_2O	kg of CO_2e/ton steel	not applicable			not applicable		
	NO_x	kg of CO_2e/ton steel	not applicable			not applicable		
	H_2	kg of CO_2e/ton steel	not applicable			not applicable		

1) The financial analysis is focused on cost of energy required per ton of steel and as the costs for an e-methane and hydrogen DRI system are the same, plant specific financials are not considered. Only for the total investment cost analysis for the Netherlands, CAPEX for a DRI system is considered; 2) Emissions for natural gas assumed to be 600 kg of CO_2/ton steel

Source: TSN IJmuiden, Agora, DIW, II3050

Comfort level of the assumption: High Medium Low

For low-emission iron & steel production, a new direct reduced iron (DRI) system is required, either for e-methane or for hydrogen at the same costs

Options considered for end-use conversion of e-methane and hydrogen – Iron & steel

		Technological feasibility	Considerations	CAPEX [EUR/ton]	OPEX [EUR/ton/yr]
New asset	E-methane	✓	Same costs assumed for a new DRI system on e-methane as for a new DRI system on hydrogen	750[1]	Not considered[1]
	Hydrogen	✓		750[1]	Not considered[1]
Depreciated CH_4 asset within lifetime (with adaptations if required)	E-methane	✗	Currently used technology not compatible with e-methane or hydrogen	n.a.	n.a.
	Hydrogen	✗		n.a.	n.a.
Lifetime extension of CH_4 asset (with adaptations if required)	E-methane	✗		n.a.	n.a.
	Hydrogen	✗		n.a.	n.a.

✓ Technologically feasible ✗ Not technologically feasible ⬚ Selected option for comparison – Based on age of current assets & technological feasibility

1) The financial analysis is focused on cost of energy required per ton of steel and as the costs for an e-methane and hydrogen DRI system are the same, plant specific financials are not considered. Only for the total investment cost analysis for the Netherlands, CAPEX for a DRI system is considered

Source: DIW

Draft

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Distribution – Process heat

Value chain steps: Conversion › Preparing for transport › Storage at export loc. › Transport-ation › Storage at import loc. › Gasification › Re-conversion › Transmission › Seasonal storage › **Distribution** › End-use conversion

As industry in cluster 1-6 are expected to be directly connected to national transmission network there would be no additional last mile cost

Comfort level of the assumption: High Medium Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: End-use conversion – Process heat

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | **End-use conversion**

Category	Parameter	Units	e-Methane/Biomethane Value	e-Methane/Biomethane Source	Comfort	Hydrogen Value	Hydrogen Source	Comfort
Stoichiometry	Heat efficiency	%	90%	TNO[LXI], IRENA[XLVII]	Medium	90%	Assumed	Medium
Plant specifics	CAPEX	EUR/kW	0	Assumed	Medium	14	CE Delft[LXII]	Low
	OPEX	EUR/kW/year	2.8	Assumed, IRENA[XLVII]	Medium	4.0	TNO[LXIII]	Low
	Retrofitted	%	100%	Assumed	High	100%	Assumed	High
	Lifetime	years	30	Assumed	High	30	Assumed	High
	Utilization	%	90%[1)]	Assumed	High	90%[1)]	Assumed	High
	Total demand	TWh/year	31	II3050[LVI]	High	31	II3050[LVI]	High
Scope 1 Emissions	CO_2	kg of CO_2e/MWh	not applicable[2)]			not applicable		
	CH_4	%	0.05%	Assumed	High	not applicable		
	N_2O	kg of CO_2e/MWh	0.61	US NETL[IX]	High	not applicable		
	NO_x	g NO_x/MWh[3)]	50	TNO[LXIV]	High	16.5	TNO[LXIV]	Low
	H_2	%	not applicable			0.25%	IEA[LXV]	Low

1) Figure assumes full load hours of 8,760 per year; 2) Emissions for natural gas assumed to be 0.22 ton CO_2/MWh from stochiometric calculation of combustion; 3) At 3% O_2

Source: TNO, CE Delft, II3050, IRENA, US NETL

Comfort level of the assumption: High Medium Low

Most industrial plants in the Netherlands have methane boilers in place which can likely be retrofitted to hydrogen boilers if needed at relatively low costs

Options considered for end-use conversion of e-methane and hydrogen – Process heat

		Technological feasibility	Considerations	CAPEX [EUR/kW]	OPEX [EUR/kW/yr]
New asset	E-methane	✓	Some especially older industrial methane boilers can be replaced by new industrial methane boilers or for new industrial plants a new methane boiler can be bought	70	2.5
	Hydrogen	✓	Some especially older industrial methane boilers can be replaced by new industrial hydrogen boilers or for new industrial plants a new hydrogen boiler can be bought	100	3.6
Depreciated CH_4 asset within lifetime (with adaptations if required)	**E-methane**	✓	Most current industrial methane boilers can likely be used without extra costs	0	2.8[1)]
	Hydrogen	✓	Most current industrial methane boilers can likely be retrofitted to hydrogen with relatively low extra costs	14	4.0[1)]
Lifetime extension of CH_4 asset (with adaptations if required)			*Not considered as an option due to relatively low CAPEX costs*		

✓ Technologically feasible ✕ Not technologically feasible ⬚ Selected option for comparison – Based on age of current assets & technological feasibility

1) Assuming 10% higher OPEX for older assets

Source: TNO, IRENA, CE Delft

Draft

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Distribution – Electricity production

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | **Distribution** | End-use conversion

As power plants are expected to be directly connected to national transmission network there would be no additional last mile cost

Comfort level of the assumption: High Medium Low

Draft

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: End-use conversion – Electricity production

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | **End-use conversion**

Category	Parameter	Units	e-Methane/Biomethane Value	e-Methane/Biomethane Source	Comfort	Hydrogen Value	Hydrogen Source	Comfort
Stoichiometry	Electricity efficiency	%	60%	TNO[LXVI]	High	60%	TNO[LXVI]	Medium
	Heat efficiency	%	30%	EPA[LXVII]	High	30%	Assumed	Medium
Plant specifics	CAPEX	EUR/kW	350[1)]	TNO[LXVI]	High	409[1)]	TNO[LXVI]	Low
	OPEX	EUR/kW/year	11	Assumed, TNO[LXVI]	Medium	12	Assumed, TNO[LXVI]	Low
	Lifetime	years	30	Assumed	High	30	Assumed	High
	Utilization	Full load hours	1,194	II3050[LXVIII]	High	1,194	II3050[LXVIII]	High
	Total demand	TWh	14	II3050[LVI]	High	14	II3050[LVI]	High
Scope 1 Emissions	CO_2	kg of CO_2e/MWh	not applicable[3)]			not applicable		
	CH_4	%	0.05%	Assumed	Medium			
	N_2O	kg of CO_2e/MWh	0.91	US NETL[IX]	Medium			
	NO_x	g NO_x/MWh[2)]	35	TNO[LXIV]	Medium	17	TNO[LXIV]	Low
	H_2	%	not applicable			0.2%	IEA[LXV]	Low

1) Including costs for increasing lifetime – 350 EUR/kW for both methane and hydrogen; 2) At 15% O_2; 3) Emissions for natural gas assumed to be 0.42 ton CO_2/MWh, source US NETL

Source: TNO, EPA, II3050, SCI

Comfort level of the assumption: High | Medium | Low

Power plants in the Netherlands are in general relatively old, but lifetime can likely be extended (possibly in combination with hydrogen retrofitting)

Options considered for end-use conversion of e-methane and hydrogen – Electricity production

Likely option in Germany due to limited current capacity

		Technological feasibility	Considerations	CAPEX [EUR/kW]	OPEX [EUR/kW/yr]
New asset	E-methane	✓	Some especially older methane power plants can be replaced by new methane power plants or buying new methane power plants can increase total capacity	700	10
	Hydrogen	✓	Some especially older methane power plants can be replaced by new hydrogen power plants or buying new hydrogen power plants can increase total capacity	770	11
Depreciated CH_4 asset within lifetime (with adaptations if required)	E-methane	✓	Some current methane power plants can likely be used without extra costs	0	11[1]
	Hydrogen	✓	Some current methane power plants can likely be retrofitted to hydrogen without lifetime extension	59	12[1]
Lifetime extension of CH_4 asset (with adaptations if required)	E-methane	✓	Most current methane power plants in the Netherlands likely require lifetime extension	350	11[1]
	Hydrogen	✓	Most current methane power plants in the Netherlands likely require lifetime extension and potential retrofitting to hydrogen	409	12[1]

✓ Technologically feasible ✕ Not technologically feasible ⬚ Selected option for comparison – Based on age of current assets & technological feasibility

1) Assuming 10% higher OPEX for older assets

Source: TNO

Draft

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Distribution – Decentral heating

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | **Distribution** | End-use conversion

Category		Parameter	Units	e-Methane/Biomethane Value	e-Methane/Biomethane Source	Hydrogen Value	Hydrogen Source
Stoichiometry		Electricity input	kWh/ton/km	0.08	EU LCA[XII]	0.6	Agora[XXIII]
Stoichiometry		Losses	%/1,000 km	0.02%	EU LCA[XII]	0.40%[1]	EU LCA[XII]
Pipeline specifics		Tariff	EUR/MWh	19[2]	Assumed	55	Calculated
Pipeline specifics	New	CAPEX	EUR m/km	not applicable		0.3	IRENA[XXXIV]
Pipeline specifics	New	OPEX	% of CAPEX	not applicable		1%	Assumed
Pipeline specifics	Retro-fitted	CAPEX	EUR m/km	not applicable		0.1	IRENA[XXXIV]
Pipeline specifics	Retro-fitted	OPEX	% of CAPEX	not applicable		1%[3]	Assumed
Pipeline specifics		Retrofitted	%	not applicable		50%	Assumed
Pipeline specifics		Lifetime	years	not applicable		55	Assumed
Pipeline specifics		WACC	%	not applicable		4%	Dutch Climate Ministry[LXIX]
Pipeline specifics		Pipeline length	km	not applicable		82,718	Calculated
Pipeline specifics		Total demand	TWh/year	47[4]	II3050[LVI]	23	II3050[LVI]
Pipeline specifics		Av. distance per end user	km	60	Assumed	60	Assumed
Scope 1 Emissions		CO_2	kg of CO_2e/MWh	Corresponding to losses in pipeline		Corresponding to losses in pipeline	
Scope 1 Emissions		H_2	kg of CO_2e/MWh	Corresponding to losses in pipeline		Corresponding to losses in pipeline	

1) Considering total loss of 1% and then dividing by 2.5 to get the loss in %/1,000 km; 2) Dividing the sum of the 2040 depreciation costs, cost of capital and OPEX by the demand; 3) OPEX as percentage of new values of pipelines; 4) Demand including fossil methane

Source: EU LCA, HyWay 27, IRENA, II3050

Comfort level of the assumption: High, Medium, Low

Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: End-use conversion – Decentral heating

Value chain steps: Conversion | Preparing for transport | Storage at export loc. | Transport-ation | Storage at import loc. | Gasification | Re-conversion | Transmission | Seasonal storage | Distribution | **End-use conversion**

Category		Parameter	Units	e-Methane/Biomethane		Hydrogen	
				Value	Source	Value	Source
Stoichiometry		Heat efficiency	%	92%[1]	TNO[LXX]	92%[1]	TNO[LXX]
Boiler specifics	CV	CAPEX	EUR per boiler	0	Assumed	5,000	Nefit Bosch[LXXI]
	CV	OPEX	EUR/year	100	Feenstra[LXXII]	100	Assumed
	CV	Number of boilers	# m	0.25[2]	II3050[LXVIII]	0.24[2]	II3050[LXVIII]
	Hybrid heat pump	CAPEX	EUR per boiler	0	Assumed	11,000[3]	Assumed, Milieu Centraal[LXXIII]
	Hybrid heat pump	OPEX	EUR/year	200	Feenstra[LXXIV]	200	Assumed
	Hybrid heat pump	Number of boilers	# m	1.7[2]	II3050[LXVIII]	1.4[2]	II3050[LXVIII]
		Lifetime	years	15	Feenstra[LXXV]	15	Assumed
		Total demand	TWh/year	23	II3050[LVI]	23	II3050[LVI]
Scope 1 Emissions		CO_2	kg of CO_2e/MWh	not applicable[4]		not applicable	
		CH_4	%	0.05%	Assumed	not applicable	
		N_2O	kg of CO_2e/MWh	0.60	US NETL[IX]	not applicable	
		NO_x	g NO_x/MWh[5]	50	TNO[LXIV]	10.5	TNO[LXIV]
		H_2	%	not applicable		0.25%	Oxford Energy Institute[LXXVI]

1) Based on HHV; 2) 2050 values for residential boilers scaled based on 2040 demand – Utilities relatively small compared to residential, so not considered here; 3) Hybrid heat pumps include both a CV and pump, price is the sum of both elements; 4) Emissions for natural gas assumed to be 0.22 ton CO_2/MWh from stoichiometric calculation of combustion; 5) at 3% O_2

Source: TNO, Milieu Centraal, Nefit Bosch, Feenstra, II3050

Comfort level of the assumption: High Medium Low

Draft

In the Netherlands, boilers for decentral heating currently almost all run on methane – Retrofitting those to hydrogen is likely not technologically feasible

Options considered for end-use conversion of e-methane and hydrogen – Decentral heating

		Technological feasibility	Considerations	CAPEX [EUR/CV]	CAPEX [EUR/HHP]	OPEX [EUR/CV /year]	OPEX [EUR/HHP /year]
New asset	E-methane	✓	Some especially older decentral methane boilers can be replaced by new decentral methane boilers – Likely limited use case for new methane boilers for newbuild	2,000	8,000	100	200
	Hydrogen	✓	Some especially older decentral methane boilers can be replaced by new decentral hydrogen boilers – Likely limited use case for new hydrogen boilers for newbuild	5,000	11,000	100	200
Depreciated CH_4 asset within lifetime (with adaptations if required)	**E-methane**	✓	Most current decentral methane boilers can likely be used without extra costs	0	0	100[1]	200[1]
	Hydrogen	✗	Lifetime extension of decentral methane boilers and/or retrofitting existing decentral methane boilers to hydrogen likely not technologically feasible	n.a.	n.a.	n.a.	n.a.
Lifetime extension of CH_4 asset (with adaptations if required)	E-methane	✗		n.a.	n.a.	n.a.	n.a.
	Hydrogen	✗		n.a.	n.a.	n.a.	n.a.

✓ Technologically feasible ✗ Not technologically feasible ⬚ Selected option for comparison – Based on age of current assets & technological feasibility

... CV ("Centrale Verwarming") ... HHP (Hybrid Heat Pump)

1) Assuming the same OPEX also for older assets due to fixed maintenance contracts

Source: Milieu Centraal, Feenstra, Nefit Bosch

Different sources have been used for the assumptions

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XVII. CO_2 intensity of electricity generation, Enerdata
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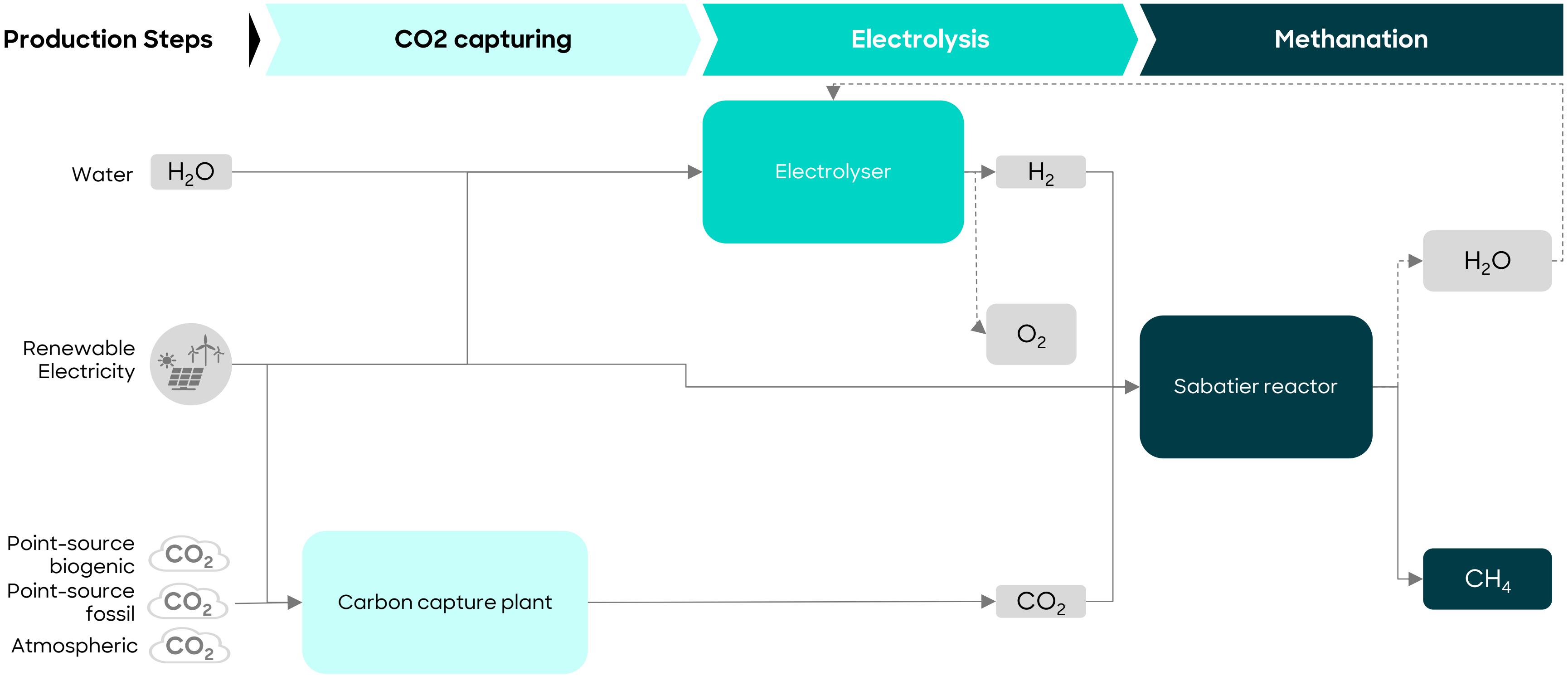
B. E-methane production technology deepdives

Sabatier methanation is the only commercialized synthesis method, employing a two-stage process, although it has a relatively low efficiency of 55-60%

Technology deepdive: Sabatier methanation



Methanation chemical reaction: $CO_2 + 4\,H_2 \rightarrow CH_4 + 2\,H_2O$

Description

- Sabatier methanation is a **two-stage process** that produces methane (CH_4) by reacting hydrogen (H_2) with carbon dioxide (CO_2) over a nickel catalyst at 200–500°C and 1–10 bar.
- In the first stage, **hydrogen** is **generated via water electrolysis**, followed by **reaction with CO_2 in the methanation stage**
- The Audi e-gas plant in Germany, with a **6 MW** electric capacity, is the world's **largest green methanation plant**
- **In China, Sabatier methanation on gas field coal is operated at GW scale**

Key parameter:

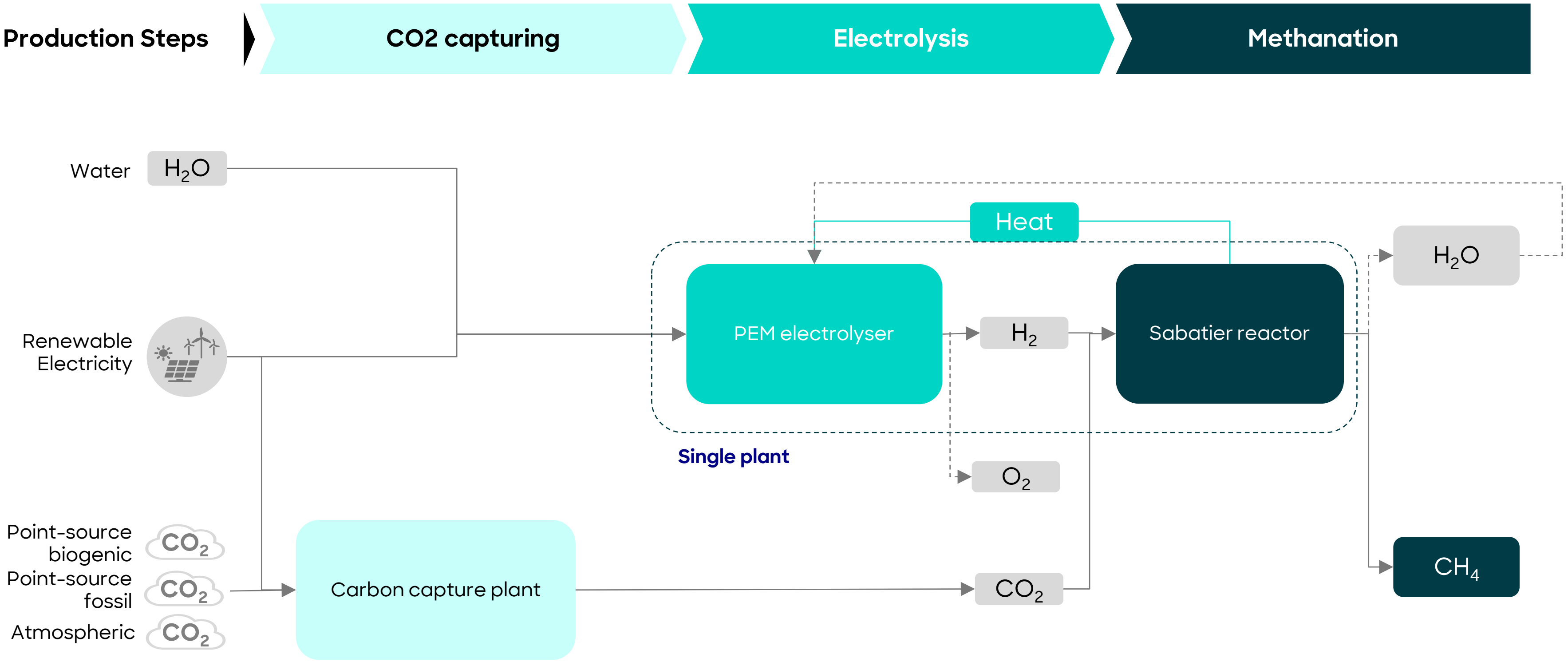
Category	Value
Technology maturity	High
Methanation temperature [°C]	200-500
Overall process efficiency[1] [%]	65%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step. The efficiency of electrolysis is expected to be 76% by 2040

Source: IEA, Japan Gas Association, Store & Go, DENA, Frontiers in Energy Research

Hybrid Sabatier methanation combines electrolysis and methane synthesis within a single plant, utilizing the heat generated during methanation

Technology deepdive: Hybrid conventional Sabatier methanation



Methanation chemical reaction: $CO_2 + 4\,H_2 \longrightarrow CH_4 + 2\,H_2O$

Description

- Hybrid Sabatier methanation **combines electrolysis and methane formation within a single plant**, utilizing the heat generated during methanation to drive the endothermic water electrolysis step
- This technology **eliminates the need for separate hydrogen procurement** and achieves **higher efficiency** than traditional Sabatier methanation through effective waste heat utilization
- A **pilot project has been launched** by Tokyo Gas and JAXA, with **commercialization expected after 2040**

Key parameter:

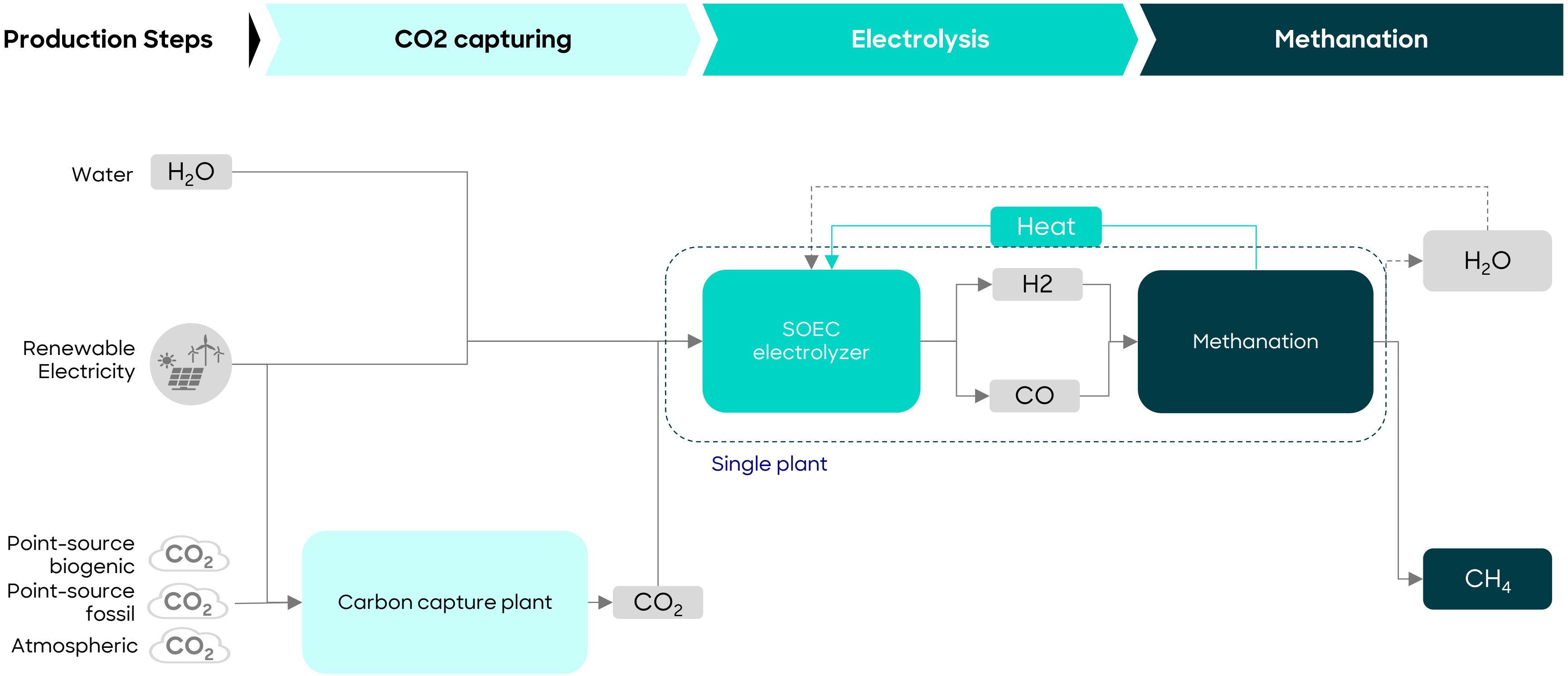
Category	Value
Technology maturity	Medium
Methanation temperature [°C]	220
Overall process efficiency[1] [%]	80%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step

Source: IEA, Japan Gas Association, Store & Go, DENA

SOEC methanation integrates high temperature co-electrolysis of H_2O and CO_2 and methane synthesis within a single plant, achieving high efficiencies

Technology deepdive: Hybrid SOEC methanation



Methanation chemical reaction: $3\ H_2O + CO_2 \longrightarrow CO + 3\ H_2 \longrightarrow CH_4 + H_2O$

Description

- SOEC methanation combines the **co-electrolysis of H_2O and CO_2 with methane synthesis in a single plant**
- This technology **eliminates the need for separate hydrogen procurement** and achieves **higher efficiency than** traditional Sabatier methanation through effective waste heat utilization
- Osaka Gas is currently conducting **pilot testing**, demonstrating efficiencies of 85% to 90%
- **Commercialization** is anticipated **in the 2040s**

Key parameter:

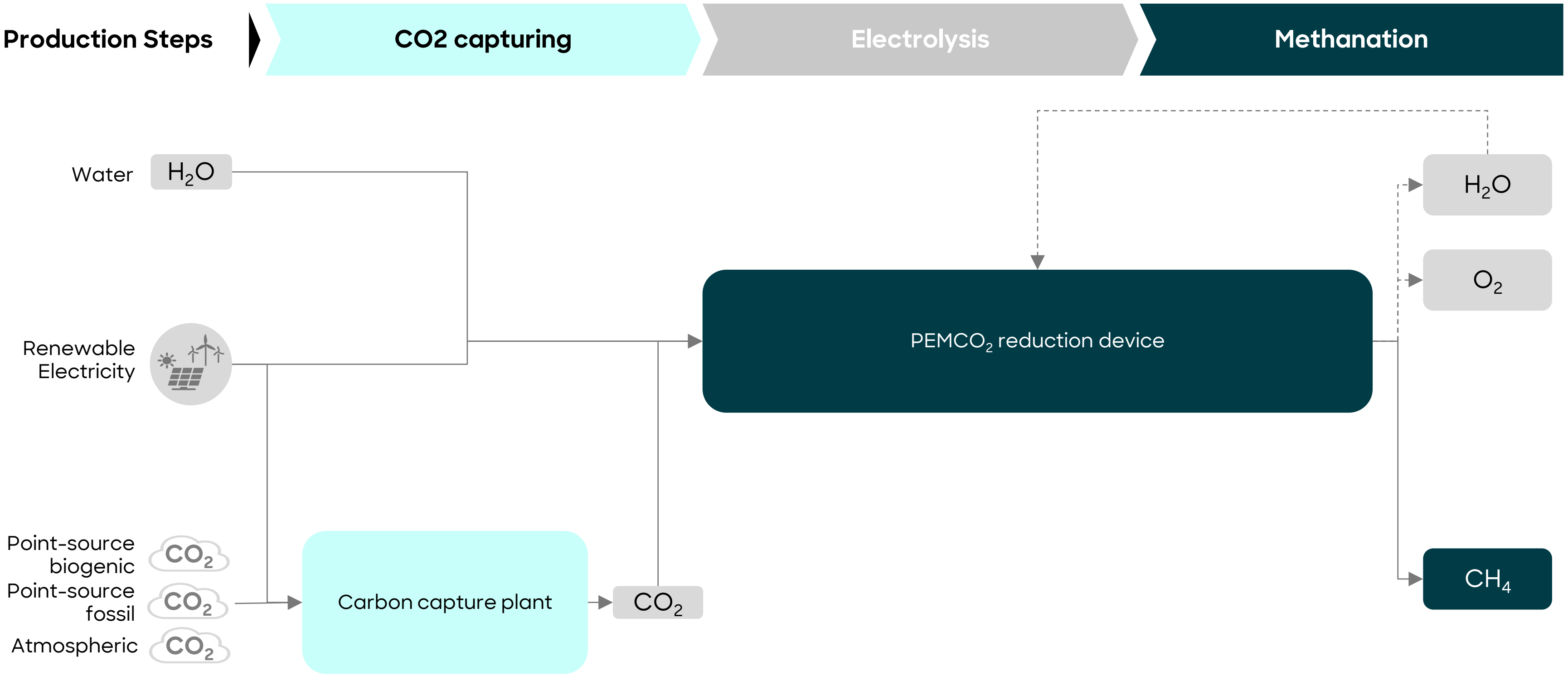
Category	Value
Technology maturity	Low
Methanation temperature [°C]	800
Overall process efficiency[1] [%]	75-90%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step

Source: IEA, Japan Gas Association, Store & Go, DENA

PEMCO$_2$ methanation uses a Polymer Electrolyte Membrane (PEM) to synthesize e-methane directly from water and CO$_2$ in one step

Technology deepdive: PEMCO$_2$ methanation



Methanation chemical reaction: $CO_2 + 4\,H_2O \longrightarrow CH_4 + 2\,H_2O + 2\,O_2$

Description

- **PEMCO₂ methanation** utilizes a Polymer Electrolyte Membrane (PEM) to **directly synthesize e-methane from water and CO₂**
- The technology **lowers equipment costs** and **operates at moderate temperatures** (60-80°C). It also eliminates the **need for precious metal cathodes** and **hydrogen procurement**
- A **pilot project has been launched** by Tokyo Gas, with **commercialization expected after 2040**

Key parameter:

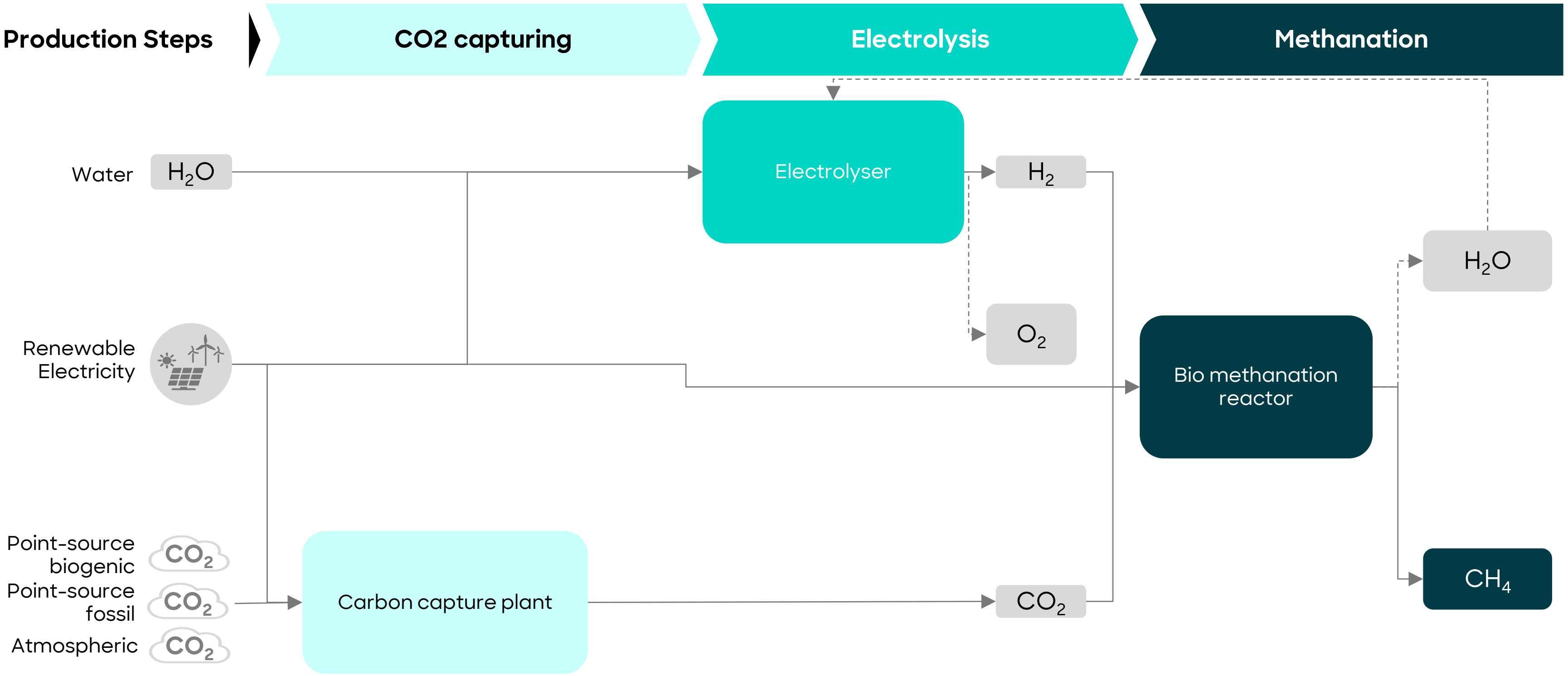
Category	Value
Technology maturity	Low
Methanation temperature [°C]	60-80
Overall process efficiency[1] [%]	70-80%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step

Source: IEA, Japan Gas Association, Store & Go, DENA

Biological methanation utilizes a two-step biochemical process where archaea act as biological catalysts to produce methane

Technology deepdive: Biological methanation



Methanation chemical reaction: $CO_2 + 4\,H_2 \longrightarrow CH_4 + 2\,H_2O$

Description

- Biological methanation employs a **two-step biochemical process** in which hydrogen is generated via electrolysis before archaea serve as biological catalysts to produce methane
- This method operates under **mild temperature and pressure conditions**
- However, **projected investment costs are higher** than those for Sabatier
- The **world's first demonstration plant** combining electrolysis and biological methanation was **established in Germany in 2015**

Key parameter:

Category	Value
Technology maturity	Medium
Methanation temperature [°C]	35-65
Overall process efficiency[1] [%]	60-65%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step. The efficiency of electrolysis is expected to be 76% by 2040

Source: IEA, Japan Gas Association, Store & Go, DENA

C. Forecasted renewable energy vector demand in NL

Draft

Energy demand estimates are based on II3050 report, developed by NL network companies to outline pathways to a climate-neutral energy system by 2050

Introduction to the II3050 report

Objective of the report

II3050 aims to identify the key choices required to achieve a climate-neutral energy system by 2050

- It provides insight into the energy infrastructure and flexibility measures required in the long term
- It addresses uncertainties in predicting future developments by using scenarios that represent realistic extremes of possible energy system outcomes

Approach of the report

II3050 uses scenarios to guide decisive policymaking

- The energy transition is a major societal challenge, demanding rapid fossil fuel reduction, renewable energy growth, and systemic changes across key sectors
- Energy infrastructure (gas, electricity, and heat networks) must undergo significant transformation to meet future demands
- Scenarios help capture uncertainties and support informed decision-making for policymakers and stakeholders

Contributors

II3050 was developed by several Dutch network companies and other relevant stakeholders

- Network companies include: Alliander, Coteq, Enexis, Gasunie, Rendo, Stedin, TenneT, and Westlandinfra
- External experts, relevant industry associations, and government agencies provided input and consultation during the study

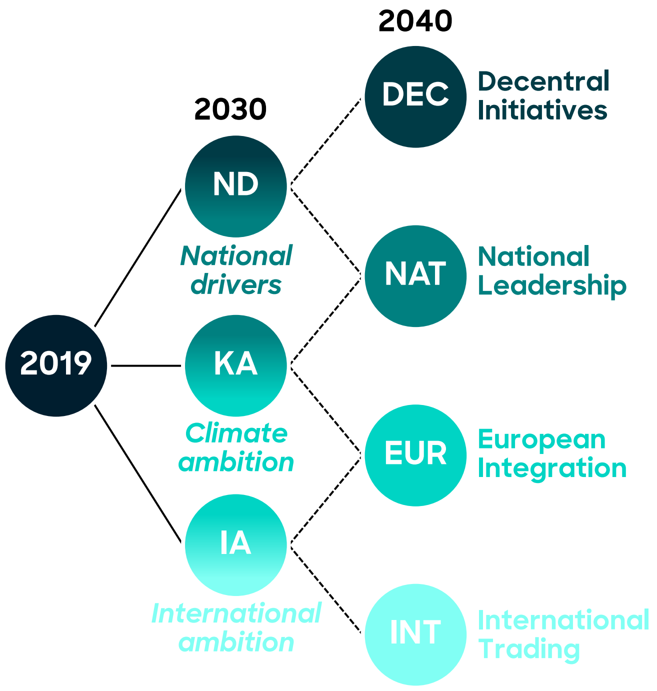
Source: II3050

II3050 report estimates the future energy demand across various scenarios – In this study the international trading scenario (INT) is the reference scenario

Scenarios used in II3050 report

IP2024 *(December 2022)*

II3050 *(October 2023)*



Scenarios aligned with RepowerEU plan

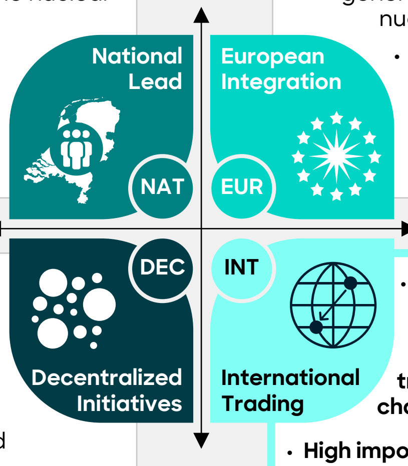
National Leadership (NAT)

- High level of government involvement and national level of organization – Electrification, energy efficiency and renewable integration
- High renewable energy generation from large scale national projects (e.g., offshore wind), flexible nuclear energy generation and hydrogen production
- Limited decline of industry – Existing industry incentivized to electrify and new green industry is stimulated (e.g., synthetic fuel production)

Collective technology choices and management by government

European Integration (EUR)

- High level of government involvement and European level of organization – Members of EU coordinate sharing energy and align policies on resources
- High adoption of CCS, limited renewable energy generation mainly from solar, wind and base load nuclear
- Limited decline of industry – Incentivized to electrify and use European biomass and hydrogen



Nationally oriented, as much self-sufficient as possible

Internationally oriented, room for import

- Low level of government involvement and regional level of organization – Decentral climate neutral projects supported by the government as a main tool for reaching climate targets
- High renewable energy generation from solar and onshore wind energy, limited adoption of CCS
- Energy-intensive industry partially leaves the Netherlands due to lack of governmental steering on energy transition

Decentralized Initiatives (DEC)

Market-driven individual solutions, government sets frameworks

- **Low level of government involvement and international level of organization – Development of economy driven by optimizing usage of global (hydrogen) trading and leveraging international supply chains**
- **High import of hydrogen and other renewable energy vectors in combination with limited green hydrogen production from offshore wind**
- **Energy-intensive industry partially leaves the Netherlands due to strong global supply chain**

International Trading (INT)

The international trading (INT) scenario which is the reference for this study as it is expected that coordinated global efforts will be required due to the shared nature of the climate crisis

Source: II3050

The energy mix per use case is expected to change in the future – Each scenario from the II3050 report assumes a slightly different energy mix in 2040

Energy demand per use case – 2019 and 2040 [TWh]

Sector		Use case	REF - 2019	DEC - 2040	NAT - 2040	EUR - 2040	Selected scenario INT - 2040	Comments
Direct industry	Energetic	Process heat *cluster 1-5*	99	71	76 ⊖	88 ⊕	73	Low-grade heat is mainly electrified
		Process heat *cluster 6*	62	50 ⊖	50	51 ⊕	50	Low-grade heat is mainly electrified
	Non-energetic	Iron and steel	32	25	23 ⊖	24	22 ⊕	Coal demand largely replaced by biomethane and hydrogen
		Refineries	23	16 ⊖	18	19 ⊕	18	H_2 produced from NG & oil in 2019 is replaced by renewable H_2
		Ammonia end-products	18	16	7 ⊖	14 ⊕	14	Natural gas demand partially replaced by biomethane & H_2
		Methanol end-products	7	4 ⊖	6	6 ⊕	5	Natural gas demand partially replaced by biomethane & H_2
		Other end-products	110	79 ⊖	96	131 ⊕	96	Oil demand partially replaced by biofuels
Mobility		Heavy duty	44	35	31	36 ⊖	38 ⊕	Busses are mainly electrified
		Light duty	87	50	51 ⊖	62	71 ⊕	Passenger cars are mainly electrified
		Shipping[1)]	4	3	4 ⊖	4	3 ⊕	Oil demand partially replaced by methane, H_2 and/or electricity
		Rail	2	3 ⊖	3 ⊖	3 ⊖	3 ⊕	Electrified almost completely
		Aviation[2)]	0.4	0.4 ⊕	0.4 ⊕	0.4 ⊕	0.5 ⊕	Oil demand partially replaced by hydrogen & batteries
Built environment		Decentral heating	172	92	88 ⊖	110	115 ⊕	Growth in total district heating demand, growth of biomethane
		District heating	6	20 ⊖	25	15 ⊕	13	Natural gas demand largely reduced (e.g., through insulation)
Electricity		Central	107	360	402 ⊖	331	288 ⊕	Natural gas demand largely replaced by renewables
		Decentral	Not evaluated as it is expected to have low demand for renewable gaseous molecules					No data available, likely limited renewable gaseous mol. demand
Greenhouses		Greenhouses	39	25 ⊖	29	28	30 ⊕	Natural gas demand largely replaced by electricity & heat

Natural gas | *Renewable gaseous molecules:* Biomethane, Hydrogen | Electricity | Heat | Coal | Oil | Biofuels | Other

⊖ Min renewable gaseous molecule demand ⊕ Max renewable gaseous molecule demand

1) Excl. ~140 TWh forecasted demand for international bunkering of synthetic and biofuels in NL, based on IRENA report on decarbonizing the shipping sector, which estimates 8.5 EJ total global shipping demand in 2040 and 6% of global bunkering to be in the Netherlands; 2) Excl. ~45 TWh forecasted demand for synthetic aviation fuel (SAF) for international aviation in NL in 2050, based on INT scenario in II3050 report

Source: II3050, Desk research

Draft

Draft

Different renewable energy vectors can be considered per use case to meet the demand for renewable gaseous molecules

Back-up – Rationale behind feasibility of renewable energy vectors per use case

Sector		Use case	E-Methane	Hydrogen	Ammonia	Methanol
Direct industry	Ener-getic	Process heat *cluster 1-5*	E-methane is used for mid to high grade heat processes	Hydrogen is used for mid to high grade heat processes	High NOx emissions make ammonia less feasible for NL, also challenges due to slow combustion	Lower energy density makes methanol less economically viable
		Process heat *cluster 6*				
	Non-energetic	Iron and steel	E-methane can be used as input for DRI systems to reduce iron ore	Hydrogen can be used as input for DRI systems to reduce iron ore	Low maturity of ammonia for steel production, challenges due to NOx	Low maturity of methanol for steel production
		Refineries	Reconverting e-methane back into hydrogen (for potential further processing) is likely economically unviable	Hydrogen is used for hydrocracking and desulfurization	No direct use for ammonia as feedstock	No direct use for methanol as feedstock
		Ammonia end-products		Hydrogen is used for conversion into ammonia	Ammonia can be directly imported rather converted on site from hydrogen	No direct use for methanol in ammonia end-products
		Methanol end-products		Hydrogen is used for conversion into methanol	No direct use for ammonia in methanol end-products	Methanol can be directly imported rather converted on site from hydrogen
		Other end-products	E-methane for producing other chemicals (oxo-chemicals, acetylene, ...)	Hydrogen for producing other chemicals (bromine, hydrogen peroxide, ...)	Limited / no use for ammonia in other chemicals	Limited / no use for methanol in other chemicals
Mobility		Heavy duty	E-methane can be used in the form of CNG[1] as fuel, niche use case for light duty as it is mostly electrified	Likely economically unviable compared to other sustainable options	High toxicity, poor flame stability and high NOx emissions make ammonia likely challenging	Methanol can directly be used as fuel, niche use case for light duty as it is mostly electrified
		Light duty				
		Shipping	E-methane in the form of e-LNG can be used as direct fuel alternative	Not a likely option for domestic shipping in the Netherlands	Not a likely option for domestic shipping in the Netherlands	Methanol can be used as fuel alternative in specialized engines
		Rail	Not a likely options for trains in the Netherlands, almost all electrified	Not a likely option for trains in the Netherlands, almost all electrified	High toxicity, poor flame stability and high NOx emissions likely challenging	No methanol powered trains operate, unlikely alternative
		Aviation	Use case e-methane in the form of CNG[1] as fuel alternative too limited	Hydrogen as a fuel alternative likely only suitable for niche applications	Use case ammonia as fuel alternative too limited	Use case methanol as fuel alternative too limited
Built environment		Decentral heating	E-methane can (directly) be used as input for methane / hybrid heat boilers	Hydrogen can be used as input for hydrogen / hybrid heat boilers	High toxicity and poor flame stability require specially designed / modified boilers, therefore likely challenging, also NOx challenges	Toxicity and potential formaldehyde emissions require specially designed / modified boilers, therefore likely challenging
		District heating				
Electricity		Central	E-methane can be used as input for methane power plants	Hydrogen can be used as input for hydrogen power plants	Potential in co-firing with coal & high NOx emissions, limited use case in the Netherlands	Low energy density makes methanol less economically feasible
		Decentral	Not evaluated as it is expected to have low demand for renewable gaseous molecules			
Greenhouses		Greenhouses	Methane can be used as input for boilers – Potential for CO_2 enrichment	Hydrogen can be used as input for boilers	Challenges as high toxicity and poor flame stability demand specialized boilers, and NOx emissions	Challenges as high toxicity and poor flame stability demand specialized boilers

Considered as a feasible option: **Not considered:** Likely not a feasible option for NL · Likely not economically viable · Not technologically proven or low maturity, feasible only for niche applications

1) Compressed natural gas

Source: II3050, Desk research

D. Value chain quantification of renewable energy vectors

Draft

Study focuses on the entire value chain from production to transportation to distribution and end-use

Renewable energy vector value chain descriptions (1/2)

Value chain steps

Production			Long-distance transportation					Reconversion	National transmission		Regional distribution & end-use	
Primary energy carrier	Other feedstocks	Conversion	Preparing for transportation	Storage at pro-duction location	Transportation	Storage at import location	Gasification	Reconversion	Transmission	Seasonal storage	Distribution	End-use conversion

Production

- **Primary energy carrier**
  Production of the main energy feedstock, being biomass or hydrogen; natural gas extraction also included in this step
- **Other feedstocks**
  Production of other feedstocks required to convert the primary energy carrier into the energy vector of interest, for example captured CO_2 for e-methane, N_2 for ammonia or dehydrogenated DBT for LOHC production
- **Conversion**
  Production of the energy vector of interest, the form in which the energy will be transported

Long distance transportation

- **Preparing for transportation**
  Potential liquefaction for shipping or compression of gases for pipeline transportation
- **Storage at production location**
  Above-ground storage in tanks at the production location or export terminals of the energy vector in the form and phase in which it will be transported
- **Transportation**
  Long-distance transportation of liquids through shipping and gases through pipelines
- **Storage at import location**
  Above-ground storage in tanks at import terminals of the energy vector in the form and phase in which it was transported
- **Gasification**
  Regasification of the gases that were liquefied for transport

Re-conversion

Potential re-conversion of the energy vector of interest into hydrogen for end-use

National transmission

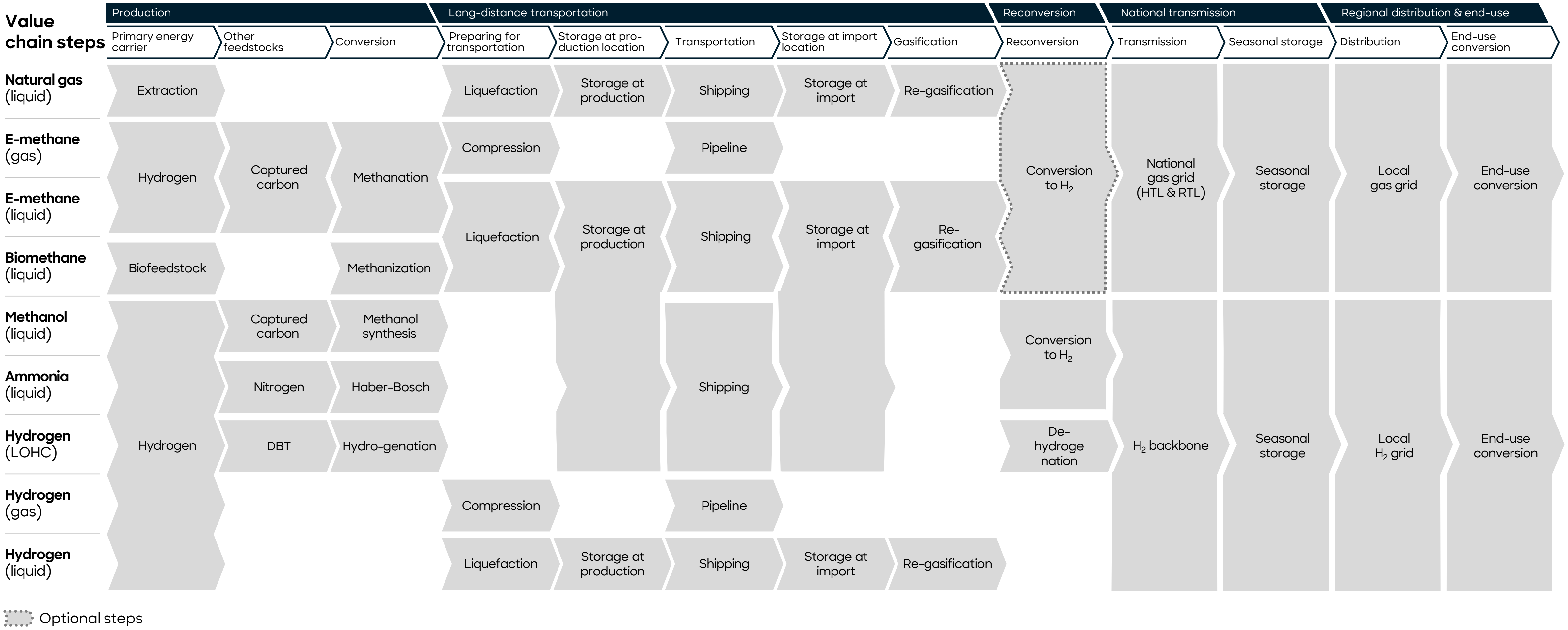
- **Transmission**
  Transport within the Netherlands via the main transmission pipelines (HTL) and regionl transmission pipelines (RTL) for methane and via the hydrogen backbone for hydrogen
- **Seasonal storage**
  Underground storage in depleted gas fields and salt caverns to accommodate temporal differences in supply and demand

Regional distribution & end-use

- **Distribution**
  Transport through low-pressure pipelines from the transmission network to the built environment
- **End-use conversion**
  Consumption of renewable energy vector for energetic and non-energetic demand in different use cases

For the shortlisted end-use cases, different energy vectors have been mapped across the entire value chain

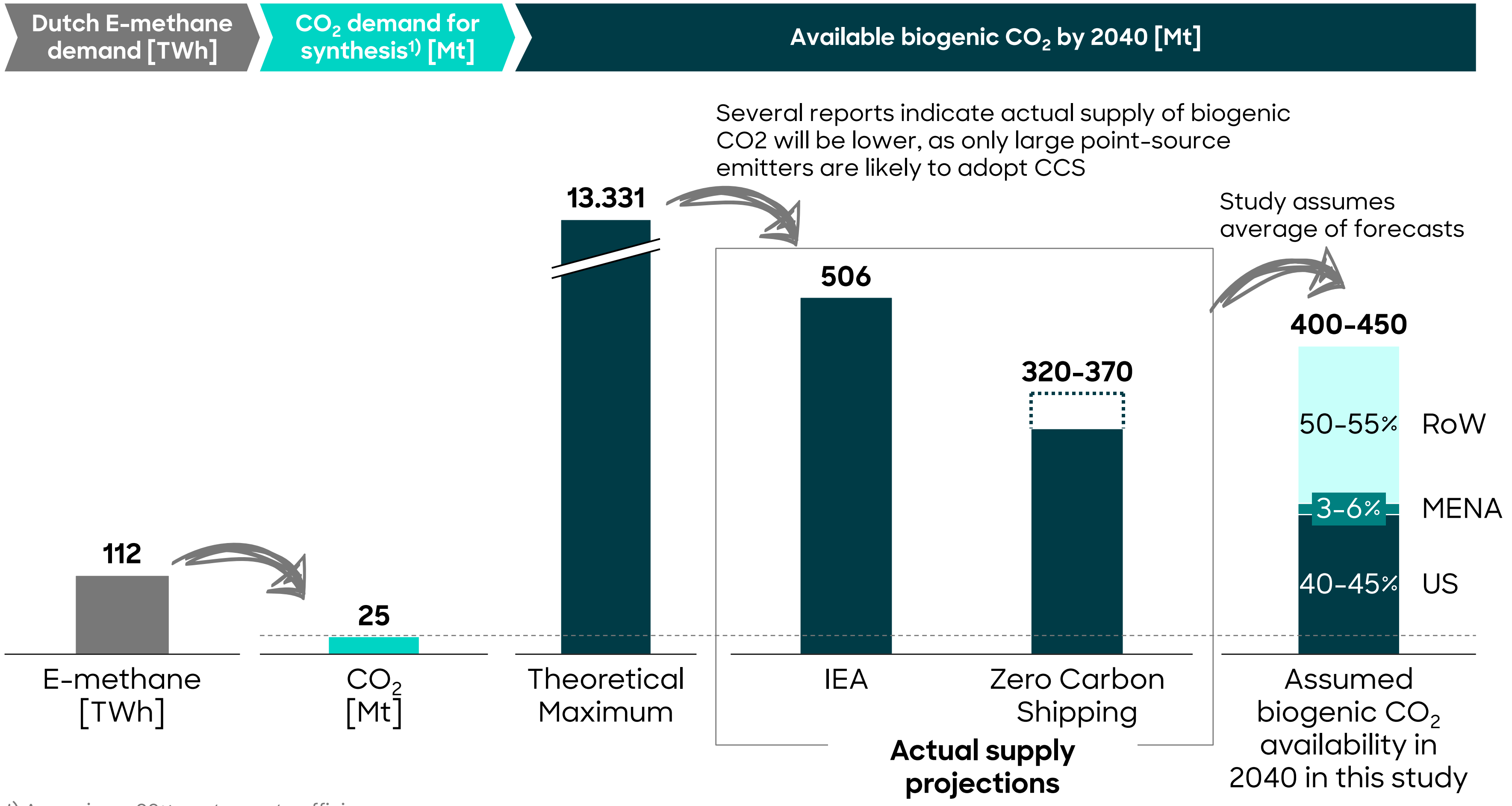
Renewable energy vector value chain descriptions (2/2)



E. Biogenic CO_2 availability

Supply of biogenic CO_2 will be limited as just the Dutch demand for e-methane would require ~13% of total available biogenic CO_2 of the US or ~150% of MENA

Availability of biogenic CO_2 in 2040 [Mt]



1) Assuming a 90% capture rate efficiency

Source: II3050, IEA, Zero Carbon Shipping

Key takeaways

- Synthesizing the projected Dutch E-methane demand for 2040 requires approximately 25 Mt of CO_2
- By 2040, 400-450 Mt of biogenic CO_2 is expected to captured and available for use
- Meeting Dutch E-methane needs would claim ~6% of global biogenic CO_2 – disproportionate for its energy demand under 1% of the global total. Moreover, other sectors might outcompete the demand for e-methane production
- Meeting the entire Dutch E-methane demand through imports from specific regions would require ~13% of the available biogenic CO_2 of the US or ~150% of MENA

Draft

F. Challenges

Challenges

The transition to a low-carbon energy system presents an array of challenges. In this chapter, we focus on the most critical challenges related to e-methane. Our aim here is to provide a more nuanced understanding of e-methane's potential and its limitations as an emerging technology to decarbonize future energy usage. First, we will focus on challenges that are solely related to e-methane, after which we will end with challenges that are also related to all new emerging energy carriers.

Technical and Productional

E-methane has a number of technical and productional challenges. Two are related to the Technical Readiness Levels (TRL) of this energy carrier. First of all, DAC technology is at the moment not fully mature (see also Chapter 5). Secondly, the production of e-methane is currently still at pilot-level quantities, while upscaling to large production quantities will probably be complex.

Other challenges relate to the production efficiency of e-methane. Like most physical and chemical conversions from one product into another the combination of electrolyser, DAC and methanation is energy intensive. This challenge is described in Chapter 4 (Figure 11) of the report.

Furthermore, when producing e-methane losses can occur. These losses might lead to the preference of direct use of hydrogen instead of adding another conversion step for producing e-methane.

Economics and Financial

The question whether e-methane will succeed in terms of being adopted by end-users will for an important part be a matter of its economics. In the end, the economics decide on e-methane's competitiveness in relation to competing energy carriers.

This study shows on the one hand that e-methane may turn out to be twice as expensive to produce in 2040 compared to biomethane. At the same time natural gas (including CCS) will be even less expensive than biomethane. So, when comparing low carbon gases, e-methane is the least competitive. However, biomethane will not be abundantly available in the future and natural gas including CCS does not contribute to the aim of reaching the 2050 climate goals.

Chapter 6 indicates that for the selected use cases, the CAPEX intensity of meeting hydrogen demand in NL is, at least, three times higher than that of e-methane. One could therefore argue that economically e-methane must become the energy carrier of choice for certain cases. However, policy makers and end-users have to make decisions today for the energy landscape of tomorrow. As long as industrial companies have no feasibility of e-methane being abundantly available ten or twenty years from now, these companies may choose a different path. This path may be, with equivalent uncertainties about availability, hydrogen. Uncertainty regarding the ultimate costs of DAC is another uncertain factor companies have to deal with. If the costs of DAC would turn out twice as high, the electricity sector and cluster 6 would perhaps be better off using hydrogen instead of e-methane.

Challenges

The transition to a low-carbon energy system presents an array of challenges. In this chapter, we focus on the most critical challenges related to e-methane. Our aim here is to provide a more nuanced understanding of e-methane's potential and its limitations as an emerging technology to decarbonize future energy usage. First, we will focus on challenges that are solely related to e-methane, after which we will end with challenges that are also related to all new emerging energy carriers.

Societal acceptance and sustainability

Accepting the idea that e-methane could in the future be a sustainable energy carrier, by policy makers as well as the public in general, is crucial for e-methane to be adopted. For biomethane and e-methane, like with natural gas, methane leakage is the biggest challenge. We are only at the beginning of understanding the current scale of methane leakage but, specifically during natural gas production, scope 1 emissions appear to be substantial. Potential e-methane emissions in the supply chain; during production, transportation or as a result of an asset being dismantled would hurt the image of e-methane as a zero-footprint energy carrier. In this respect it is important to note that in this study the production of e-methane results in scope 2 emissions via the CO_2 grid intensity for the electricity that is used for DAC. A potential lack of confidence by policy makers and/or end-users that e-methane will be a zero-footprint energy carrier in the future might hinder its adoption. It will take substantial efforts in terms of adopting global standards and convincing interest groups to tackle this issue.

Another element that could affect public perception negatively is the supposed lock-in for natural gas. This means that the public sees synthetic renewable fuels as a reason for the continuation of the fossil fuel-based infrastructure. Policy makers and end-users aim for the transition to sustainable energy carriers. Interest groups will argue that in a situation where energy carriers are still being dependent on the fossil fuel-based infrastructure the transition to sustainable energy carriers is delayed or even thwarted. One can argue however that no lock-in risk exists because phasing out fossil fuels is the only direction to go in order to tackle climate change. Continued and reuse of current fossil infrastructure for renewable energy sources like e-methane is evidently an opportunity and not a risk.

Challenges

The transition to a low-carbon energy system presents an array of challenges. In this chapter, we focus on the most critical challenges related to e-methane. Our aim here is to provide a more nuanced understanding of e-methane's potential and its limitations as an emerging technology to decarbonize future energy usage. First, we will focus on challenges that are solely related to e-methane, after which we will end with challenges that are also related to all new emerging energy carriers.

Challenges related to all new emerging energy carriers

The study contains many assumptions on the speed of development of technologies and the future costs associated with the production and transportation of e-methane. This is especially true for the costs and the grid intensity related to DAC. This makes the outcome of the future costs of e-methane for end-users uncertain as well as e-methane's competitiveness (relative costs) against other energy carriers. Whatever the future costs of e-methane, in general it is clear that electrification of all end-users and industries is not a viable alternative.

A major hurdle for all new emerging energy carries such as hydrogen and e-methane is the establishment of robust carbon accounting and certification systems which is a requirement under the Renewable Energy Directive (REDII and the forthcoming REDIII revisions). Ensuring the carbon neutrality of e-methane requires reliable methods for measuring, reporting, and verifying (MRV) emissions throughout its life cycle. Although progress has been made, these systems remain underdeveloped. This also applies to countries outside Europe, for example in the case that e-methane is sourced from MENA.

Another critical issue is the inconsistency of policy incentives. While government interventions through mechanisms like carbon pricing, taxes, and subsidies are vital to make e-methane competitive with fossil fuels, such incentives vary widely across the European Union and its member states. This disparity creates market imbalances, discourages private investment, and complicates the development of a unified European approach to e-methane adoption.

The lack of global standardization is an uncertainty for all energy carriers. Without internationally agreed-upon standards for production, quality, and sustainability criteria, cross-border trade in e-methane may be hindered. This lack of alignment affects not only the feasibility of international market integration but also the harmonization of decarbonization goals and the realization of large-scale ambitions.

Permitting and environmental regulations present a significant challenge. Securing permits for the construction of e-methane production facilities, green hydrogen and DAC is often a lengthy and complex process, influenced by strict environmental regulations. These delays can increase project costs and slow the pace of scaling up production, undermining the role of e-methane in the energy transition.

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