

Master thesis

A Comparative Techno-Economic Analysis of
Different E-Methanol Value Chains Relevant to the
Netherlands

Sustainable Energy Technology

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Master thesis

A Comparative Techno-Economic Analysis of Different E-Methanol Value Chains Relevant to the Netherlands

by

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Preface

Six years ago, my academic career at the Technical University of Delft started with the BSc program in Mechanical Engineering. Over the years I slowly discovered my passion for sustainability. The ever-emerging problem of climate change has ignited my interest. I decided to combine my knowledge of mechanical engineering and passion for sustainability by enrolling in the MSc program in Sustainable Energy Technology. During the past two years, I focused on energy storage with batteries and hydrogen, as well as on energy production with photovoltaic panels and wind turbines. These topics include a financial aspect which is as important as the technical side. The bridge between those two areas is what I have focused on in this research and on which I will hopefully focus in the coming years.

During the past six years, and especially the last nine months, I have developed complex problem-solving capabilities which I am going to use throughout my future career. In addition to the substantive skills, I have developed myself in terms of social interactions by working with people of many different nationalities.

I want to thank my supervisors and colleagues at Power2X for the interesting conversations and insights about the energy transition. I would especially like to thank Rajat and Andy for their supervision and guidance through the research period at Power2X, and Ruby and Rowan for their weekly check-ins and problem-solving sessions. Besides them, I want to express my deepest gratitude to Prof. Dr. Ir. E.L.V. Goetheer for being a friendly and very helpful supervisor from the university during the past nine months. With this thesis, I would like to provide even more insights into the energy transition and encourage people to accelerate the energy transition by seeking new opportunities.

*R.M. Elswijk
Amsterdam, September 2024*

Abstract

This study conducts a comparative techno-economic analysis of various E-methanol value chains relevant to the Netherlands, with the objective of identifying the most efficient supply strategy using hydrogen sourced from Saudi Arabia. The study encompasses four distinct scenarios: Scenario 1 involves the export of CO₂ from the Netherlands and the import of E-methanol from Saudi Arabia; Scenario 2a examines the import of liquid hydrogen (LH₂); Scenario 2b evaluates the import of hydrogen in the form of ammonia (NH₃); and Scenario 2c considers the import of hydrogen via Liquid Organic Hydrogen Carriers (LOHC).

A comprehensive comparative model has been developed to assess both the technical and economic dimensions of each scenario, covering aspects such as production, storage, transportation, and conversion within the respective value chains. The results highlight key cost drivers and potential optimization opportunities, offering insights into the economic feasibility and technical efficiency of each scenario.

Under the base case conditions, Scenario 1 (CO₂ export with E-methanol import) emerges as the most economically viable option, with a Levelized Cost of Methanol (LCOM) of 1.4 €/kg. Among the hydrogen import scenarios, ammonia (Scenario 2b) is identified as the most cost-effective option for long-distance hydrogen import.

Sensitivity analyses are conducted to understand the impact of variable factors, revealing that hydrogen feedstock price and methanol production capacity substantially influence the LCOM across all scenarios. Despite these variations, Scenario 1 consistently remains the most effective supply strategy.

This research offers valuable insights for policymakers and stakeholders in the energy sector, highlighting the potential benefits and challenges associated with adopting E-methanol as a sustainable fuel alternative.

Keywords

E-methanol; green hydrogen; hydrogen carriers; green ammonia; LOHC; renewable CO₂; comparative study; techno-economic analysis (TEA); conceptual process design; hydrogen transport; hydrogen storage

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Nomenclature

Abbreviations

Abbreviation	Definition
AEM	Alkaline anion Exchange Membrane
ATM	Atmospheric Pressure
AWE	Alkaline Water Electrolyzer
BECCS	Bio-Energy with Carbon Capture and Storage
BOG	Boil Off Gas
CAPEX	Capital Expenditures
CEPCI	Chemical Engineering Plant Cost Index
CcH ₂	Cryo-compressed Hydrogen
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage
CF	Capacity Factor
CGH ₂	Compressed Gaseous Hydrogen
CH ₃ OH	Methanol
CHP	Combined Heat and Power Plant
CL	Chile
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
DAC	Direct Air Capture
DBT	Dibenzyltoluene
E-MeOH	Electrified Methanol
EUR	Euro
FID	Final Investment Decision
FIO	Free In and Out
GHG	Green House Gas
Gt	Gigaton
GWP	Global Warming Potential
H ₂	Hydrogen
HHV	Higher Heating Value
IEA	International Energy Agency
IrO ₂	Iridium Oxide
J-T	Joule-Thomson
kg	Kilogram
km	Kilometer
KOH	Potassium Hydroxide
kt	Kiloton
kWh	Kilowatt Hour
LCA	Life Cycle Assessment
LCO ₂	Liquid Carbon Dioxide
LCOH	Levelized Cost of Hydrogen
LCOM	Levelized Cost of Methanol
LH ₂	Liquid Hydrogen
LHV	Lower Heating Value
LNG	Liquid Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LPG	Liquid Petroleum Gas

Abbreviation	Definition
NL	Netherlands
nmi	Nautical Miles
MeOH	Methanol
MJ	Mega Joule
MR	Mixed-Refrigerant
Mt	Megaton
MWh	Megawatt Hour
NH ₃	Ammonia
NPV	Net Present Value
O ₂	Oxygen
OPEX	Operational Expenditures
PEM	Proton Exchange Membrane
Pt	Platina
PtF	Power to Fuel
PtX	Power to X
PV	Photovoltaic
SA	Saudi Arabia
SOE	Solide Oxide Electrolyzer
SOEC	Solid Oxide Electrolyzer Cell
TRL	Technology Readiness Level
TWh	Terrawatt Hour
UAE	United Arab Emirates
USD	United States Dollar

Symbols

Symbol	Definition	Unit
C	Capacity	[m ³]
c	Cost	[€/kWh]
d	Distance	[m]
E	Energy	[J]
e	Electricity	[kWh/t]
M	Stoichiometric ratio	[-]
P	Pressure	[bar]
Q	Flow rate	[t/y]
t	Time	[s]
v	Velocity	[km/h]
V	Volume	[m ³]
Δ	Delta	[-]
η	Efficiency	[%]

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Introduction

1.1. Background

The global energy landscape is shifting remarkably as the world seeks to combat climate change and improve energy security by transitioning to cleaner, more sustainable energy sources (IEA 2023b). Achieving the goals of the Paris Agreement necessitates extensive greenhouse gas (GHG) emission reductions in all sectors (Wissner et al. 2023). This requires substantially reducing carbon emissions by substituting fossil fuels with renewable energy sources. However, due to the intermittent nature of power supplied by renewables, it will be essential to adopt secondary energy sources that can effectively store renewable energy in the future (Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024).

Electrification presents a viable solution for significantly reducing GHG emissions in several sectors, particularly when electricity is generated from zero or low-carbon fuels such as nuclear energy, renewables, and natural gas. Nevertheless, for high-energy applications such as aviation, heavy-load vehicles, and marine transport, electrification is less feasible because of the low energy density of batteries, thus necessitating the conversion of electricity into other forms of energy. This necessity has given rise to the relatively new concept known as Power-to-Fuel (PtF), which has gained popularity over the past few years due to its wide and diverse applications. As its name suggests, PtF involves converting power into carbon-neutral synthetic fuels that can replace fossil fuel-based products (Nemmour et al. 2023).

The core of the PtF concept is hydrogen (H_2) gas, which serves as the primary intermediate for converting power to hydrogen-based synthetic fuels. Currently, most hydrogen is derived from natural gas using steam reforming of methane. In contrast, the renewable variant, which is called green hydrogen, is produced through water electrolysis and powered by renewable electricity sources such as hydro, wind, or solar power. This results in minimal GHG emissions when splitting water into hydrogen and oxygen. Consequently, green hydrogen is considered a green energy carrier and a sustainable fuel suitable for use in transportation, the gas industry, heating, power generation, and the manufacturing of chemicals such as ammonia and methanol (Ghenai et al. 2023).

The production of fuels from hydrogen using renewable carbon dioxide (CO_2) promotes the development of less carbon-intensive fuels. Renewable CO_2 is obtained by capturing CO_2 from renewable sources (IRENA 2021b). CO_2 can be captured from the air or from various processes such as power plants and industrial streams. Additionally, CO_2 can be obtained from renewable sources like biomass combustion and biogas production (IEA 2020).

PtF technologies offer a pathway for producing hydrogen-based synthetic fuels and chemical feedstocks such as methane, methanol, ammonia, jet fuel, etc. This provides a low capital-intensive decarbonization approach to reduce CO_2 emissions in the energy sector. Renewable PtF technologies facilitate energy transition by enabling long-term storage of excess and unutilized renewable energy, thereby addressing intermittency issues and enhancing energy supply security (Varone et al. 2015). The last decade has already shown significant advancements in the production and utilization of these

technologies. Innovations in technology have improved the efficiency and reduced the costs of renewable energy sources, making sustainable fuels more competitive with fossil fuels.

Despite these advancements, the widespread adoption of these hydrogen-based fuels remains challenging (Noussan et al. 2021). It is still very expensive because of its high production costs, and scaling up the production amounts to meet global energy demands requires substantial investments in, for example, infrastructure.

This work reviews the value chain of one of these hydrogen-based synthetic fuels between two designated countries: Saudi Arabia and the Netherlands. Methanol stands out as a promising fuel for PtF technologies due to its versatility and numerous applications. It is a valuable feedstock for producing a variety of chemicals and products. Additionally, methanol serves as an excellent solvent and a clean synthetic fuel (Nemmour et al. 2023).

A comprehensive techno-economic assessment has been conducted on the production, storage, transportation, and, when necessary, the re-conversion of renewable methanol and its feedstocks. This renewable methanol, called E-methanol, is suitable as a sustainable fuel and can be used as a chemical substance in other industries.

Exploring the feasibility of the E-methanol value chain offers significant value in areas like policies, existing knowledge, and businesses. Understanding the technical and economic efficiency of E-methanol production and everything that goes with that, can inform policymakers about the potential benefits and challenges of adopting E-methanol as a sustainable fuel. From an academic and research perspective, a comprehensive analysis of the E-methanol value chain enriches the existing body of knowledge on E-fuels. It provides a detailed case study that can be used for future research and development in the field of renewable fuels.

This research is done in cooperation between the TU Delft and a business in the energy transition, called Power2X. For businesses involved in the production, distribution, and utilization of sustainable fuels, and thus E-methanol, insights into the value chain's efficiency can highlight cost-saving opportunities and competitive advantages.

Power2X

Power2X is an accelerator of the energy transition, founded in 2020 and based in Amsterdam. The company specializes in realizing next-generation energy assets at an industrial scale for both their business partners and themselves. As a scale-up company, Power2X is at the forefront of advancing sustainable energy solutions.

Operating as a project developer and consultancy in the energy transition sector, Power2X focuses on developing clean and green molecules, including green and blue hydrogen, ammonia, methanol, and biofuels. These projects are designed to transform the global energy production landscape by leveraging innovative technologies and sustainable practices. By facilitating knowledge and projects of these alternative energy sources, Power2X aims to significantly reduce carbon emissions and promote a more sustainable energy infrastructure.

Their work involves collaborating with various stakeholders to design, develop, and implement large-scale projects that reduce the carbon footprint associated with traditional energy sources. Through these efforts, Power2X is critical in accelerating the transition to a low-carbon economy and fostering the adoption of renewable energy solutions worldwide (Power2X 2024).

1.2. Research questions

The aim of the research is established according to the relevance of this study which is defined by a research gap as described in Section 2.4, and the emphasis on what the results of this report can bring to existing literature, policies, and businesses. The objective of this research is summarized in this Section, which contains the research question and its sub-questions.

This study aims to provide a clear understanding of the optimal layout of the E-methanol value chain. This is done by creating different layouts of this value chain and evaluating all its components. The objective of this study is summarized in the following research question.

Which E-methanol value chain scenario is the most technical and economically effective for ensuring E-methanol availability in the Netherlands, based on a comparative analysis of distinct supply strategies using hydrogen sourced from Saudi Arabia?

To answer this question properly the following sub-questions were formulated:

1. What are the main cost drivers in different scenarios of the value chain to get E-methanol in the Netherlands using hydrogen from Saudi Arabia?
2. What is the most economically feasible way to import hydrogen from Saudi Arabia to the Netherlands for E-methanol production?
3. What are optimization opportunities for the value chain of E-methanol?

1.3. Research approach

This research creates two different scenarios of the E-methanol value chain. The E-methanol considered is produced from green hydrogen and biogenic CO₂. The first step is to employ extensive literature research to get a clear overview of all the components considered in this value chain. Each component in this chain is extensively studied from a technical and economic point of view. Two distinct scenarios have been developed, both resulting in E-methanol being available in the Netherlands.

The first scenario involves captured CO₂ from the Netherlands, where it is also liquefied and temporarily stored before being transported to Saudi Arabia by ship in its liquid form. Upon arrival in Saudi Arabia, the liquid CO₂ is temporarily stored again and converted back to its gaseous form when required. Hydrogen is produced in Saudi Arabia and, along with the imported CO₂, fed into a methanol synthesis reactor. The synthesized methanol is then temporarily stored in Saudi Arabia before being loaded onto a ship and transported back to the Netherlands. In the Netherlands, additional temporary storage facilities are available for the methanol, which is subsequently distributed and utilized domestically and in the surrounding regions. Figure 1.1 illustrates scenario 1 considered in this study with its system boundaries. The CO₂ capture technology, the hydrogen production technology, and the end-use of methanol are out of the scope of this study and thus excluded from the system boundary.

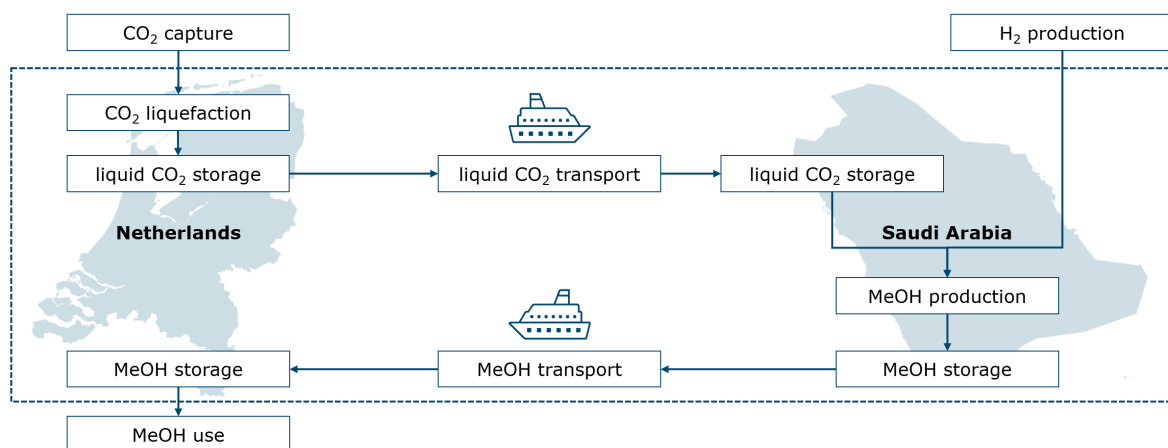


Figure 1.1: Scenario 1 and its system boundary: CO₂ export with E-MeOH import

The second scenario involves sourcing and transporting hydrogen from Saudi Arabia to the Netherlands. Before transportation, the hydrogen is converted into liquid hydrogen (LH₂), ammonia (NH₃), or a liquid organic hydrogen carrier (LOHC). The importation of the various hydrogen carriers is designated as Scenario 2a, Scenario 2b, and Scenario 2c, respectively.

After conversion, the substance requires temporary storage at a terminal in Saudi Arabia. From this storage facility, the hydrogen-carrying substance is loaded onto a ship and transported to the Netherlands. Upon arrival at the terminal in the Netherlands, it is temporarily stored again. Subsequently, the substance is split into pure hydrogen and the other associated chemicals to be ready for methanol

synthesis. The captured CO_2 and hydrogen are then fed into a methanol synthesis reactor located near the terminal. Following production, the methanol is distributed and utilized domestically and in the surrounding regions. Figure 1.2 illustrates scenario 2 considered in this study with its system boundaries. The CO_2 capture technology, the hydrogen production technology, and the end-use of methanol are in this scenario also out of the scope of this study and thus excluded from the system boundary.

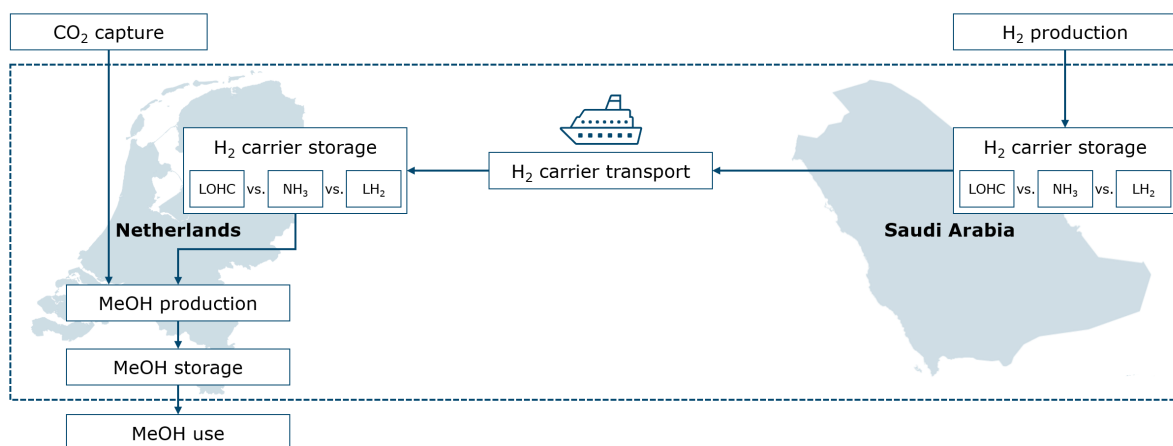


Figure 1.2: Scenario 2: hydrogen import in three different forms

After constructing the scenarios, a detailed study of each component is necessary. This starts with a technical analysis of each component described in the scenarios, with technical characteristics being derived from the literature and adapted to the specific conditions of the scenario. Following the technical analysis, an economic evaluation is conducted for each component, scaling key characteristics from the literature to match the specific quantities involved. These technical and economic assessments provide the necessary input for the decision-making model.

The subsequent step involves developing a comprehensive model that compares both scenarios' technical and economic performances in the base case. This model aims to provide insights and answers to the research questions. Once the base case scenario results are obtained, a sensitivity analysis is performed to evaluate the impact of varying certain parameters and to identify potential optimization opportunities. This approach ensures a thorough comparison and robust conclusions regarding the layout of the E-methanol value chain to ensure methanol availability in the Netherlands.

1.4. Document outline

This chapter introduces the key topics addressed in this master's thesis and outlines the research questions and the approach taken to answer them. Chapter 2 provides a comprehensive overview of the literature review conducted during the first phase of the research. It presents the current state-of-the-art scientific literature related to these topics, identifying a research gap that highlights the relevance and contribution of this study to the existing body of knowledge in this field.

Following the literature review, Chapter 3 details the methodology employed in this study, including the underlying assumptions. Chapter 4 presents the findings obtained from the analysis of the different scenarios, which are then thoroughly evaluated and discussed in the same chapter. This chapter also includes an extensive analysis of the sensitivity analysis results. Finally, Chapter 5 summarizes the study's conclusions and answers the research questions.

2

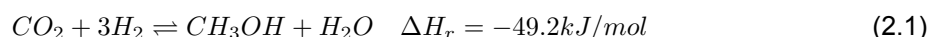
Literature review

This Chapter comprises a literature review of the essential topics covered in this study. This chapter is divided into three subsections, each of which covers a chemical compound considered in the value chain of methanol. First, Section 2.1 describes the current state of the art of the methanol industry, with a focus on E-methanol. This section also elaborates on the different components of the value chain which includes the handling of methanol itself. Then, Section 2.2 covers the first feedstock for the methanol production: hydrogen. This section lists available literature about the handling of different hydrogen carriers considered suitable for transport in this study. Third, Section 2.3 elaborates on the other feedstock for the methanol production: CO₂. This section elaborates on the different components of the handling of CO₂ considered in this study. This comprehensive literature research will provide the present knowledge and allow to define the current knowledge gap. The relevance of this study arises from the research gap.

2.1. Methanol

Methanol (MeOH) is a colorless, fairly volatile, flammable, and poisonous liquid and the simplest compound in the long series of organic compounds known as alcohols. Methanol is a clean energy source, and it's one of the most important industrial petrochemical products that is used as a fuel, solvent, and intermediate substance for other components' production. At standard ambient conditions, methanol is in a liquid state and it is relatively easy to handle, transport, and distribute. The methanol industry spans throughout the world and currently, the methanol production is still largely based on fossil fuels with a global production in 2023 of 98 million tons (Mt) per year emitting 0.3 gigatons (Gt) of CO₂ annually which accounts for $\approx 10\%$ of the total emissions in the chemical sector. The methanol demand is expected to increase to 500 Mt by 2050 and that results in releasing 1.5 Gt of CO₂ per annum if industries keep relying only on fossil fuels (Nemmour et al. 2023). Besides being a common building block in chemical synthesis, it is also a clean-burning fuel that can replace conventional fuels (Cameli et al. 2024).

Methanol is synthesized by the catalytic hydrogenative conversion of carbon dioxide to methanol as per reaction 2.1 (Nemmour et al. 2023). The catalytic reaction is exothermic that operates in ranges of temperature and pressure of 200-300 °C and 50-100 bar, respectively with a H₂:CO₂ ratio of 3:1 with the presence of the copper/zinc oxide based catalyst (Rivarolo et al. 2016).



As can be seen in figure 2.1, methanol can be classified per carbon source used as low or high carbon methanol and this depends on the feedstock and the conversion route along with the associated emissions. Brown methanol production is largely based on coal gasification. When the methanol production process is based on natural gas reformation, it's considered as grey methanol. Brown and grey methanol both have a high carbon intensity. The carbon footprint of methanol produced from coal

is nearly 300 g CO₂eq/MJ, which is even 3 times higher than that of natural gas-based methanol (MI 2022).

However, when methanol is obtained from renewable sources it is considered low-carbon intensive and this kind of methanol is called blue or green. In the current methanol industry, only a very small amount of about 0.2% of the produced methanol comes from renewable sources (IRENA 2021a). Renewable methanol significantly cuts CO₂ emissions by up to 95%, reduces nitrogen oxide emissions by up to 80%, and eliminates sulfur oxide and particulate matter emissions, showing its potential to contribute substantially to decarbonizing various sectors (MI 2024b). The different variants of renewable methanol are bio-methanol, bio-E-methanol, and E-methanol. In this research only one specific variant of green methanol with a low carbon intensity is considered: E-methanol.

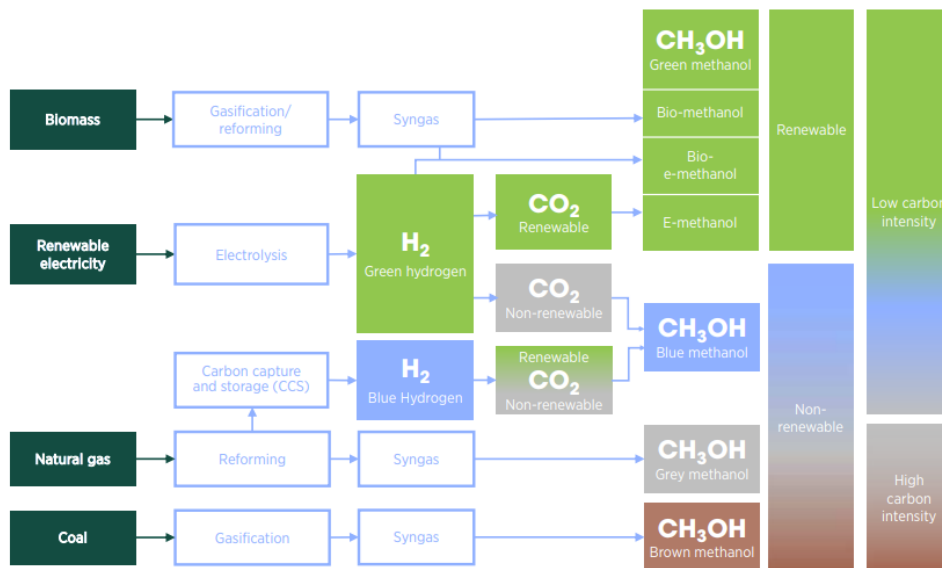


Figure 2.1: Proposed classification of methanol from various feedstocks (IRENA 2021a)

A study by (Tabibian et al. 2023) conducted a statistical and analytical investigation of the methanol value chain and its different production routes, with the main goal of identifying technical and economic challenges associated with transitioning to renewable methanol.

(Tabibian et al. 2023) concludes that methanol offers several technical advantages, including versatile production methods, renewable feedstock options, ease of handling, and diverse applications. Economically, although renewable methanol is more expensive than fossil fuel-derived methanol, its environmental benefits—such as reduced greenhouse gas emissions—justify its higher cost, provided there is sufficient policy support. Additionally, focusing on high-value downstream products can enhance profitability and facilitate the methanol industry's transition to sustainability.

E-Methanol : Electric-based methanol (E-MeOH) had the potential to substitute fossil-based hydrocarbons as the prominent feedstock in the production of climate-neutral synthetic fuels and organic chemicals because E-MeOH can be fully produced from renewable energy sources. To be considered as 100% renewable, all feedstocks have to originate from renewables. E-MeOH is produced from captured CO₂ and green hydrogen, which is produced from renewable electricity (Nemmour et al. 2023).

The production of methanol from CO₂ and hydrogen can be considered as a mature technology. Almost identical proven and fully commercial technologies are used to make methanol from fossil fuel-based syngas and can be used for E-MeOH production. The production of E-MeOH on a large scale will depend on the availability of inexpensive green hydrogen and CO₂, as well as the capital cost of the plant. From a cost perspective, the main drivers will be the cost of the renewable power needed to generate the required green hydrogen which is part of the OPEX, as well as plant utilization rates

which is part of the CAPEX. Currently, E-MeOH remains costly to produce from these sources (IRENA 2021a).

Before the production, storage, and transport of methanol are covered in this Section of the literature review, the current state of the methanol industry is sketched in the following Subsection.

2.1.1. State of the industry

According to the International Renewable Energy Agency (IRENA 2021b), E-methanol is already being produced worldwide by building prototype and demonstration units.

As an example of already-existing methanol production from hydrogen and carbon dioxide, the Carbon Recycling International plant in Iceland can be mentioned (Schorn et al. 2021). Carbon Recycling International is the global leader in CO₂ to methanol technology, with over 200 kt per year of installed sustainable methanol production capacity. To this date, they are the only company in the world who have realized dedicated CO₂ to methanol conversion plants at commercial scale (CRI 2024).

As represented by the Methanol Institute, in the last two years, the E-MeOH industry has been a significantly growing segment of the global methanol market. The Methanol Institute is actively involved in promoting the use of renewable methanol. Together with Finland's GENA Solutions Oy, they developed a database with bio-methanol and E-MeOH projects. This database identifies 131 production projects globally and these projects are expected to rapidly expand the total projected capacity to 19.7 million tons (Mt) by 2029 as can be seen in figure 2.2. Among them, 84 E-MeOH facilities together have a share with a total capacity of 13.1 Mt (GENA Solutions 2024) (MI 2024b). E-methanol is produced using renewable electricity while bio-methanol is produced using biomass, the production of E-methanol could end up costing less than bio-methanol production if both fuels mature (IRENA 2021a).

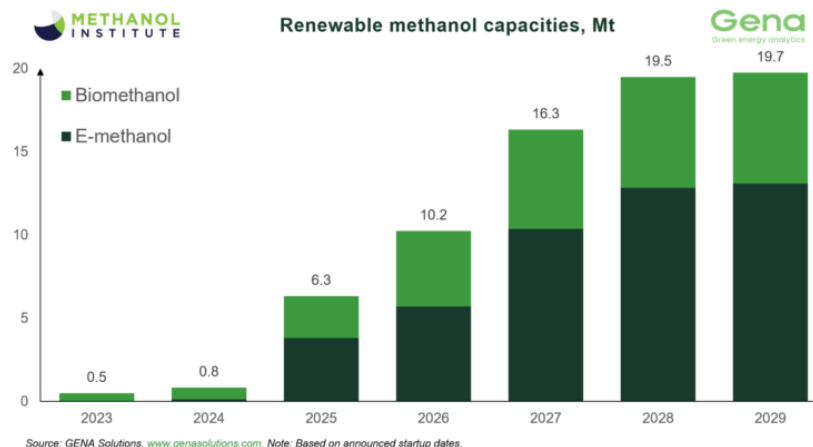


Figure 2.2: Capacities of renewable methanol in Mt (GENA Solutions 2024)

In addition to figure 2.2, 73% of these projects are still in the early stages of development which are the feasibility or the pre-feasibility phase. 21% of the projects are in the engineering phase, 3% is in the construction phase and the final 3% is already operational.

When looking at the methanol projects from a geographical point of view, most of the methanol project startups are expected to occur in China, with North America and Europe in second and third place respectively. These three regions are responsible for almost 90% of the total capacity additions till 2030 (GENA Solutions 2024).

(Liquid Wind 2024) is a leading developer of sustainable electro-fuel production facilities with a vision to reduce the world's dependency on fossil fuels. They have solid pipeline of projects in development in the Nordic countries with the goal of reaching 10+ projects with a Final Investment Decision (FID) by 2030. Three of their projects are currently under construction: Örnköldsvik (50 kt/yr E-MeOH), Sundsvall (130 kt/yr E-MeOH), and Umeå (130 kt/yr E-MeOH).

Economics

The cost of E-MeOH depends to a large extent on its feedstocks, which are hydrogen and CO₂. In 2021, the cost of E-MeOH was estimated to be in the range of USD 800-1600/t, assuming CO₂ is sourced from combined renewable sources. If CO₂ is obtained by direct air capture (DAC), then E-MeOH production costs would be in the range USD 1200-2400/t (IRENA 2021a).

(IRENA 2021a) made a cost estimation of the renewable E-methanol production up to 2050 as shown in Figure 2.3. The current production cost levels for E-methanol with CO₂ from combined renewable sources range from 820 USD/tonne to 1620 USD/tonne. This cost includes the cost of the feedstocks and the methanol synthesis.

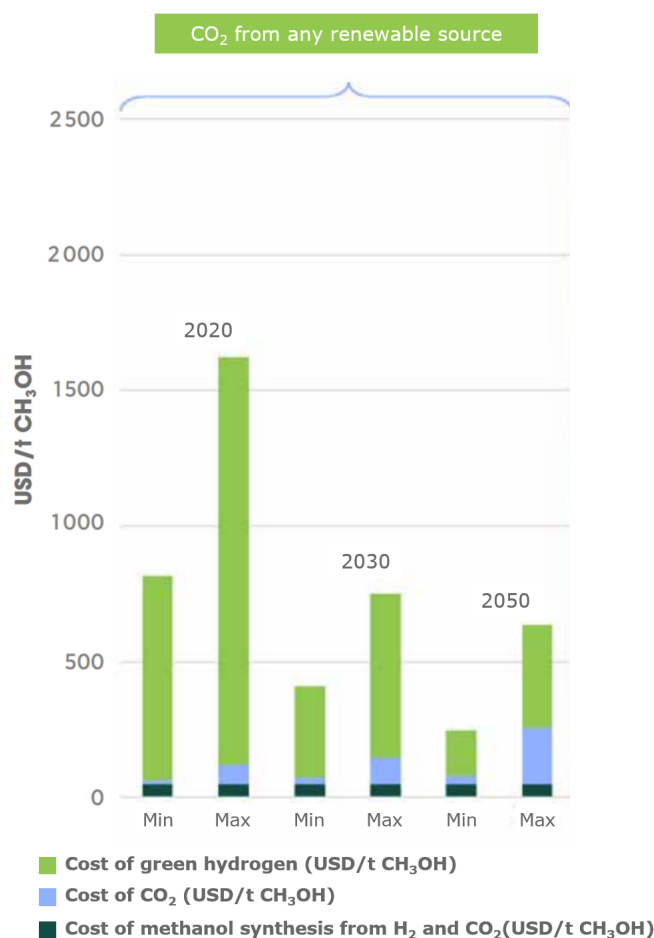


Figure 2.3: Estimated costs of renewable E-methanol up to 2050 (IRENA 2021a)

2.1.2. E-Methanol production

The production of E-MeOH is a PtX process, where electricity is the base feedstock and MeOH is the final product. Electricity is used mainly to generate H₂ via electrolysis. A classic MeOH production needs syngas, which contains CO and CO₂. Since syngas is fossil-based, an alternative carbon source must be considered. Carbon capture technology can provide CO₂, either from points of emission or directly from air. Therefore, E-MeOH is produced mainly through green hydrogen and direct catalytic CO₂ hydrogenation using an adiabatic fixed-bed catalytic reactor. Copper and Zinc are reported to be the main components of the catalysts, along with different additives. Pre-heated hydrogen and carbon dioxide are catalytically converted into methanol by means of the CO₂ hydrogenation (2.2), reverse water-gas shift (2.3) and CO hydrogenation (2.4) reactions (Sollai et al. 2023) (Rahmat et al. 2023):





This process conventionally operates within a temperature range between 250 and 300 °C and a pressure between 50 and 100 bar. The conversion efficiency is maximized when the reaction operates with an optimal stoichiometric ratio $M = 2$, where M is defined as in equation 2.5 (Pozo et al. 2022) (Sollai et al. 2023).

$$M = \frac{[H_2] - [CO_2]}{[CO] + [CO_2]} \quad (2.5)$$

The next step is the purification of methanol. In this process, the liquid methanol product was forwarded to multiple distillation columns to remove light components from a methanol and water mixture. Finally, the methanol product comes out of the final distillation column with a certain purity in the liquid state (Safder et al. 2024).

(Cameli et al. 2024) states according to a conceptual process design of an E-MeOH plant that the energy consumption for E-MeOH production consists of 349 kWh/t MeOH for electricity, 1.99 MWh/t MeOH for heating duties, and 3.41 MWh/t MeOH for cooling duties.

2.1.3. Methanol storage and transport

For methanol, which is in a liquid state at atmospheric pressure and ambient temperature, storage and transport are relatively easy and stable. The way of storing and transporting methanol is approximately the same as those used for other liquid fuels but requires some specific safety considerations. Moreover, its transport is very affordable with negligible losses (MI n.d.[b]).

Storage

Methanol can be stored in large above-ground tanks. Guidelines for designing, fabricating, constructing, repairing, and safeguarding these above-ground methanol storage tanks are essentially the same as those for liquid transportation fuels such as ethanol and gasoline, and flammable liquid feedstocks such as benzene, acetone, and toluene. However, the physical and chemical properties of methanol are unique. So, some considerations of tank storage are unique to methanol (MI 2016).

According to (MI n.d.[a]) the methanol is stored in different places during the process of storage, loading, unloading, and transportation:

- **Docks and marine terminals** Storage facilities at ports and marine terminals are typically floating roof tanks, specially made for methanol handling.
- **Tank farms** Tank farms at facilities such as refineries and chemical plants have dedicated methanol storage and handling systems. These tanks are typically above ground, and piping is above ground and overhead in pipe racks.
- **Portable containers**

Transport

Trans-oceanic transport of methanol is similar to that for other hydrocarbon liquids, such as crude oil, gasoline, and diesel. Current technologies such as crude oil cargo vessels can be used to transport methanol with only minor modifications (Wang et al. 2023). Double-hulled vessels are commonly used by shippers and will likely become the standard as world production increases. Special provisions for tanker shipment are cleanness (to prevent contaminating the methanol), methanol leak detection, appropriate firefighting equipment and pump piping, hose, and gasket materials that are suitable for methanol service. Accidental releases into the open ocean are to be avoided but are considered to pose less of a threat to the environment than crude oil, bunker fuel, gasoline, or diesel fuels (MI n.d.[a]). According to (Al-Breiki et al. 2021), the BOG rate in the transportation phase for MeOH is 0.005 %/day.

Moreover, used as a fuel itself, methanol also offers advantageous characteristics for transportation (Tabibian et al. 2023):

- Liquid fuel is compatible with current car technology and may be combined with gasoline and ethanol.
- Because of its high octane and favorable combustion properties, methanol-specific engines may match the greatest diesel efficiency while still adhering to pollution emission standards.
- It is a reliable fuel.
- Methanol is an excellent long-term transportation fuel alternative for reducing greenhouse gas emissions produced from sustainable biomass.

Ownership options for shipment

There are two approaches regarding the operation of a ship for bulk transportation from a financial viewpoint: either own a ship and be responsible for everything related to its operation or hire a ship and hold the shipowner responsible for part of the expenses of its operation in exchange for a charter rate, see figure 2.4 (Meca et al. 2022).

Fixed costs		Voyage costs		
CAPEX	Fixed Operating Costs	Proportional costs	Non-proportional costs	Loading and unloading
Vessel ownership				
Bareboat charter				
Time charter				
Voyage charter				

Figure 2.4: Options for ship operation for bulk transportation of goods (Meca et al. 2022)

Three main types of charters exist; bareboat, time, and voyage. In a bareboat charter, the charterer assumes full control and responsibility for the vessel and its expenses, including crew, maintenance, and insurance. In contrast, a voyage charter sees the shipowner covering all voyage costs except cargo handling under free in and out (FIO) terms. Time charter involves the shipowner bearing fixed costs while the charterer covers non-fixed expenses.

For consistent terminal-to-terminal operations, bareboat or time charters are preferable due to lower capital immobilization and cost compared to voyage charters (Villalba-Herreros et al. 2023). 'Lower capital immobilization' in this context means that bareboat and time charters require less capital to be tied up by the charterer compared to the total costs involved in voyage charters. This is particularly beneficial for companies that prefer not to have large amounts of their capital tied up in shipping assets and operations.

A time charter is favored over bareboat by companies not specialized in shipping, as they don't benefit from reduced operating costs typical in specialized firms. Consequently, a time charter is chosen as the most suitable option in this context (Villalba-Herreros et al. 2023). Bulk cargo ship time charter rates vary depending on the market and cargo type. These ownership options account for all types of bulk transportation.

2.2. Hydrogen

Hydrogen is one of the most important chemical substances on earth and can be obtained through various techniques using renewable and nonrenewable energy sources. When talking about green hydrogen, hydrogen is obtained via electrolysis using renewable electricity. Hydrogen itself has a low energy density, which makes it more challenging to store and transport than fossil fuels. To make it easier to store and transport hydrogen, hydrogen can be converted into hydrogen-based fuels and feedstocks. These kinds of hydrogen-based fuels and feedstocks are called hydrogen carriers (IEA 2019a). A hydrogen carrier is a specific type of liquid hydride or liquid hydrogen that transports large quantities of hydrogen from one place to another and they can make use of existing infrastructure for

their transport, storage, and distribution (Kojima et al. 2022). The benefits of these hydrogen-based fuels and feedstocks have to be weighed against the costs of converting hydrogen into these products.

The hydrogen industry is divided into four major parts: production, storage, transportation, and use. In this section, the storage and transport of hydrogen in different forms is covered. The production and use of hydrogen itself is out of the scope of this research, and therefore only briefly mentioned in this literature review.

2.2.1. Hydrogen production from electrolysis

Hydrogen can be produced from various sources of raw materials including renewable and non-renewable sources (Kumar et al. 2022). Hydrogen is classified into different color shades i.e. blue, gray, brown, black, and green respectively based on their hydrogen production technology, energy source, and environmental impact (Ajanovic et al. 2022). In this study, green hydrogen is used for the production of E-MeOH, and therefore only the production of green hydrogen is covered in this Section.

Green hydrogen is produced from renewable water and electricity by electrolysis process, in this process water is split into hydrogen (H_2) and oxygen (O_2) under the influence of electricity with zero carbon emissions (Carmo et al. 2013).

Electrolyzers are used to produce green hydrogen. In the literature of (Nasser et al. 2022) and (El-Shafie 2023) the different types of electrolyzers are explained:

- **Proton Exchange Membrane Electrolyzer (PEM)** PEM produces high-purity hydrogen at lower temperatures, typically between 70–90°C. They utilize IrO_2 and Pt as anode and cathode catalysts, respectively, with a Nafion membrane acting as a solid electrolyte. These electrolyzers benefit from rapid reaction kinetics due to the acidic nature of the electrolyte and metallic electrode surfaces, allowing safe operation at atmospheric pressure on the anode side. Despite these advantages, PEM electrolyzers face difficulties in scaling up for large-scale applications, necessitating extensive analysis to validate their characteristics and expected lifespan.
- **Alkaline Water Electrolyzer (AWE)** Alkaline water electrolyzers, commonly used in large-scale hydrogen production, employ nickel and cobalt oxides for the anode and cathode materials, respectively. Potassium hydroxide (KOH) serves as the electrolyte, typically in a 30-40% concentration, with the alkalinity maintained by circulating the electrolyte across both electrodes. Operating at moderate temperatures of 65–100°C and a voltage range of 1.8–2.4 V, these electrolyzers achieve a conversion efficiency of 60–80%. A notable advantage is their ability to function without requiring catalysts. However, the primary challenge is electrode corrosion due to the alkaline solution.
- **Alkaline Anion Exchange Membrane Electrolyzer (AEM)** AEM electrolyzers represent the latest advancement in water electrolysis technology, combining the benefits of both alkaline and PEM electrolyzers. They use non-noble catalyst materials, which lower hydrogen production costs, and an anion exchange membrane. Despite the potential for lower overall costs and stable H_2 production, AEM electrolyzers currently suffer from poor catalyst activity and low membrane conductivity. Therefore, further research and development are required to improve their performance, efficiency, and suitability for industrial-scale hydrogen production.
- **Solid Oxide Electrolyzer (SOE)** SOE operates at significantly higher temperatures, ranging from 900–1000°C. They use nickel-based electrodes and ceramic materials for the electrolyte. The high operating temperatures increase cell efficiency and reduce the required electricity for hydrogen separation, allowing the use of alternative heat sources such as waste heat and nuclear energy. However, the elevated temperatures accelerate electrolyte degradation, reducing the lifespan of the Solid Oxide Electrolyzer Cell (SOEC). Current demonstrations of SOECs are limited to kilowatt-scale operations, highlighting the need for further development.

The power consumption for a megawatt-scale electrolysis plant varies between 4.5 and 7.5 kWh per cubic meter of hydrogen produced, equivalent to 50–80 kWh/kg H_2 . For the environmental impact of the process to be the lowest possible and for the products to be considered renewable, the electrolyzer needs to be powered with electricity generated from renewable energy sources (Sollai et al. 2023).

Green hydrogen market in Saudi Arabia

Two main debates are rising in the discussion about the future of hydrogen. The first is the demand-related question about applications and sectors in which hydrogen can and should be used. The second one is related to the supply side of hydrogen. What will be the final selling price of hydrogen, to make climate change mitigation cost-efficient? (Ueckerdt et al. 2024).

The production cost of hydrogen is influenced by several elements, including the power source and manufacturing technique (G. Aziz et al. 2024). Future green hydrogen production costs are also anticipated to show a region-dependent range, which depends on regional renewable electricity costs or prices, supply chain specifications, and technological developments (Ueckerdt et al. 2024).

An important cost factor is determined by whether electrolyzers are grid-connected and thus have to pay higher electricity prices, or whether green hydrogen projects are directly connected to renewable, such that electricity costs are determined by low renewable electricity (Ueckerdt et al. 2024).

As determined in this study, Saudi Arabia will be the source of green hydrogen, leveraging its abundant sunshine and wind for economically attractive production. Despite competition from other countries, Saudi Arabia's large hydrocarbon reserves and renewable energy potential position it as a leading low-cost hydrogen producer with the lowest production cost in the world. This advantage could make it a significant global exporter of low-carbon hydrogen if international commerce develops (G. Aziz et al. 2024).

According to (Hasan et al. 2021), the cost of producing green hydrogen in Saudi Arabia was estimated to be \$2.41/kg in 2021. With a projected production cost of \$1.48/kg by 2030, the delivered cost of hydrogen from Saudi Arabia to the Port of Rotterdam is expected to be between \$3.50 and \$4.50/kg, including conversion, transportation, and dehydrogenation (G. Aziz et al. 2024).

According to (Alhadhrami et al. 2024), the LCOH prospects for 2030 of hydrogen production in Saudi Arabia range from 2.34 to 3.08 \$/kg.

(Abdelshafy et al. 2024) states that if the highest renewable energy potential for wind in Saudi Arabia is considered (Capacity Factor (CF) is 0.73), the LCOH will be 4.28 €/kg H₂, and if a low renewable energy potential for wind is considered (CF is 0.4), the LCOH will increase to 4.91 €/kg. These values are also prospects for 2030.

Figure 2.5 shows a world map that presents the levelized cost of hydrogen (LCOH) production from renewable, solar PV, and onshore wind (IEA 2023c). This map indicates regions where the production of hydrogen is relatively cheaper than others.

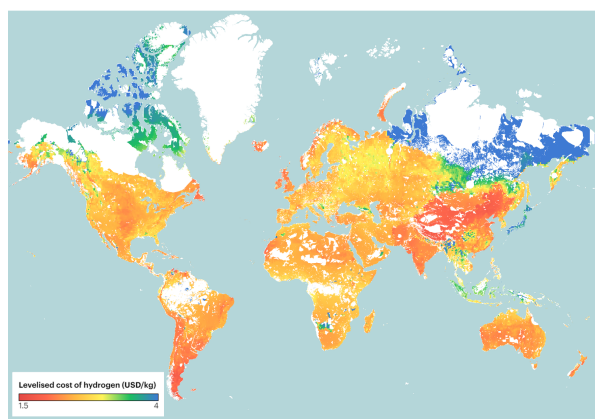


Figure 2.5: LCOH production from renewables map

When looking at the hydrogen market in Europe, the European Hydrogen Observatory's estimations show that hydrogen production costs in Europe for 2022, utilizing grid electricity, have an average value of 9.85 €/kg H₂. When the electricity is supplied by electrolysis, this average estimated cost is 6.86 €/kg H₂ (EHO 2023). However, the cost of hydrogen production technologies in the world, within the

next decade, is estimated to decrease drastically. To be more specific, by 2030, it is expected by the Hydrogen Council that the costs of renewable hydrogen production could decrease to a range of USD 1.4/kg to 2.3/kg, this accelerates green hydrogen investments in certain regions by 2028–2034 (HC 2023).

2.2.2. Hydrogen storage and transportation

Because hydrogen is the lightest element and has an extremely low density (0.09 kg/m^3 at ATM conditions), displacement of this element is a key challenge (Yang et al. 2023). This makes it more challenging to store and transport hydrogen than fossil fuels. To make it easier to store and transport hydrogen, hydrogen can be converted into hydrogen-based fuels and feedstocks (IEA 2019a). The form in which hydrogen is stored and transported determines not only its transportation method but also the ways of hydrogen utilization (Yang et al. 2023).

Storage

Hydrogen storage systems can be divided into two categories: physical-based and material-based storage. When hydrogen is stored in a physical-based storage system, the hydrogen is stored by altering its physical state, namely increasing the pressure (compressed gaseous hydrogen (CGH_2)) or decreasing the temperature below its evaporation temperature (liquid hydrogen (LH_2) or using both methods (cryo-compressed hydrogen storage, (CCH_2)). In the case of material-based storage, additional materials as 'carriers' are applied, which can bond hydrogen molecules or atoms. This enhances the storage density and safety compared with those of physical-based storage systems (Yang et al. 2023).

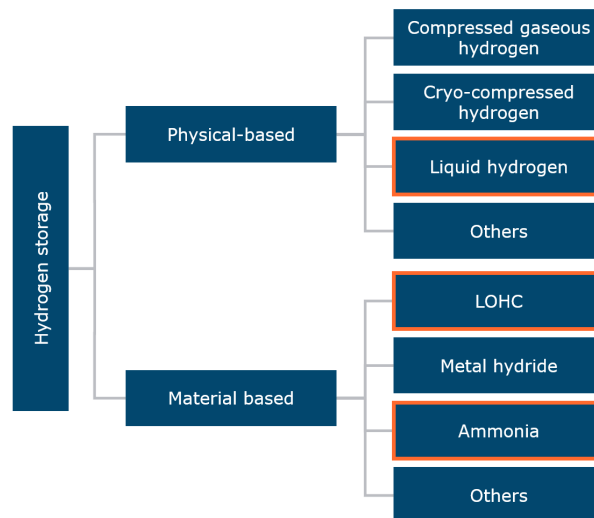


Figure 2.6: Overview of hydrogen storage technologies (Yang et al. 2023)

A special class of material-based hydrogen carriers are power fuels or E-fuels. They can not only combine with hydrogen molecules and release them according to their demands but also can be used as fuels (Yang et al. 2023). Not all power fuels are economically suitable to be deployed as hydrogen carriers, but ammonia is a suitable power fuel for this application (Andersson et al. 2019).

Not all possible technologies for hydrogen storage are considered in this research. The ones considered in this research allow relatively easy storage and transportation of hydrogen: liquid hydrogen (LH_2), ammonia (NH_3), and a LOHC. In Figure 2.6, the considered technologies are highlighted. These technologies are further reviewed in the subsequent Sections.

Transport

Depending on the volume of hydrogen, delivery distances, and local circumstances, hydrogen can be transported from the production site and distributed to the end consumer in multiple ways (Ball et al. 2015). There are three main categories for hydrogen transport based on currently existing and mature transport systems: road transportation, pipeline transportation, and shipping. An overview of

the possibilities in each category is shown in Figure 2.7 (Yang et al. 2023). As highlighted in this figure, only shipping is considered as a transport medium in this study because this is the only suitable option for all the forms of hydrogen and hydrogen carriers considered.

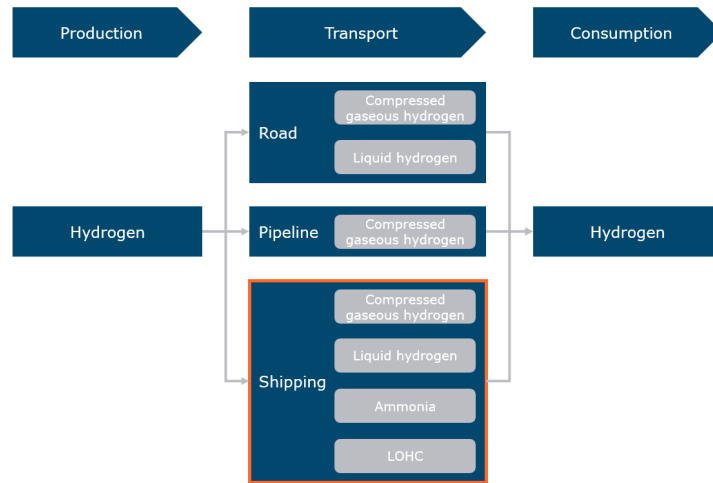


Figure 2.7: Overview of hydrogen transport options (Yang et al. 2023)

In a global green hydrogen economy, transporting hydrogen over sea becomes a necessity and the most economical option. This is particularly relevant for international hydrogen trade, where countries with abundant renewable energy capable of generating green hydrogen for export are geographically distant from countries that need to import hydrogen (Brändle et al. 2021).

Unfortunately, until now just a few pilot projects are aiming to ship hydrogen across countries and even over continents. Some studies predict that future hydrogen supply chains will be established in the future. These supply chains include transporting large quantities of hydrogen in elemental form (LH_2) or compound form (NH_3 or LOHC), (Ortiz-Cebolla et al. 2021).

2.2.3. Liquid hydrogen

The lower volumetric energy density of hydrogen becomes a major obstacle to the long-term storage and long-distance transport of H_2 . The volumetric energy density of H_2 can be increased when it is liquefied (Geng et al. 2023). Like gaseous hydrogen, liquid hydrogen is odorless, tasteless, and colorless. The main characteristics of liquid hydrogen distinguishing it from gaseous hydrogen are its very low temperature and liquid phase. The liquid phase leads to significantly higher density (M. Aziz 2021).

Liquid hydrogen offers the possibility of increasing the density up to 71kg/m^3 by cooling the hydrogen below $-252\text{ }^\circ\text{C}$ (Reuß et al. 2017). The technique to liquefy is much more difficult and consumes more energy than compression (Yang et al. 2023), but it is a relatively well-established technology at a small scale and it does not require complex re-conversion compared to hydrogen carriers (Weichenhain 2021).

Hydrogen liquefaction

As hydrogen is a permanent gas, it cannot be liquefied only by compression at 1 ATM. To liquefy the hydrogen, it should be cooled down to its critical temperature ($-240\text{ }^\circ\text{C}$), which then must be stored in vacuum-insulated vessels below the boiling temperature ($-253\text{ }^\circ\text{C}$ at 1 ATM). Through cryogenic cooling, the volume of hydrogen is reduced by 1/848, leading to significantly efficient hydrogen storage (M. Aziz 2021). Large-scale hydrogen liquefiers must employ catalytic ortho-to-parahydrogen conversion because the reaction is highly exothermic and otherwise very slow (Valenti 2016).

During hydrogen liquefaction, throttling and Joule-Thomson effects are important concepts. Throttling is generally employed in large gas liquefaction cycles after increasing the pressure and/or decreasing the temperature to create non-ideality. Conversely, the Joule-Thomson (J-T) effect deals with the maximum

inversion temperature compared to the ambient temperature (M. Aziz 2021). Note that the rate of temperature changes of a real gas with respect to isenthalpic pressure is defined as the J-T coefficient. When the pressure is decreasing and the gas temperature is below its inversion temperature, the J-T coefficient is positive. If the gas pressure is above the inversion temperature, the J-T coefficient is negative and the gas warms up (Yang et al. 2023).

Hydrogen liquefaction can be done in different ways. (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024) compares three different process configurations: a liquid nitrogen pre-cooled Claude cycle, a mixed-refrigerant (MR) pre-cooled Claude cycle, and an MR cascade process. Based on their performances, the MR pre-cooled Claude cycle is the best choice for the liquefaction process in this literature.

The hydrogen-liquefaction work strongly depends on inlet conditions and outlet conditions (Valenti 2016). In the liquefaction process via the MR pre-cooled Claude Cycle from (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024), the gaseous hydrogen is fed at a temperature of 25°C and a pressure of 20 bar, and the liquid hydrogen is delivered at a temperature of -252°C and a pressure of 1.3 bar.

The energy consumption for this hydrogen liquefaction process consists of 5.61 MWh/t_{H₂} of cooling energy provided by cooling water, 3.54 MWh/t_{H₂} of refrigerant energy provided by refrigerant, and 8.32 MWh/t_{H₂} of electric energy.

Liquid hydrogen storage and transport

Liquid hydrogen storage involves keeping hydrogen in its liquid state at cryogenic temperature, typically around -253°C (Yang et al. 2023). Once liquefied, hydrogen is stored in cryogenic tanks. These tanks are generally cylindrical shaped and placed on land. Cryogenic vessels adopt sophisticated materials to reduce conductive and radiant energy flow from the environment to the stored fluid as well as vacuum-insulated jackets to eliminate convection flow (Valenti 2016).

During the storage of liquid hydrogen, vaporization occurs. The phenomenon in which liquid hydrogen vaporizes to its gaseous state during storage is usually referred to as boil-off. Boil-off can occur due to several causes or mechanisms, and active or passive efforts can minimize the boil-off (M. Aziz 2021).

Modern cryogenic tanks for LH₂ storage are largely based on tanks developed for LN₂ with minimal modifications. These tanks use perlite and a vacuum of 10–2 mbar for insulation. The typical boil-off loss of current LH₂ tanks varies from 1% to 5% per day (Derking et al. 2019). In practice, it has become more and more popular to adequately utilize the evaporated hydrogen and thus to reduce the effective boil-off loss (Yang et al. 2023). When integrating a refrigeration system into a multi-layer insulated tank, it is even possible to fully eliminate the loss (Swanger et al. 2017).

The shipment of hydrogen in its liquid state has become increasingly attractive in recent years. This is mainly due to the high volumetric density, as well as the fact that experiences summarized from other mature cryogenic technologies can be easily integrated into the development of an LH₂ shipping system (Yang et al. 2023). For example, this technology is derived from liquefied natural gas (LNG) shipping configurations, which transport LNG already at -162 °C (Kimura et al. 2019). Terminals used for LNG shipment can be upgraded for LH₂ import and/or export.

LH₂ shipping faces the same challenge as stationary storage technology, the boil-off loss. Re-liquefaction on the ship is currently not available (Yang et al. 2023). During maritime transport, a quantity of LH₂ amounting to 0.2%/day is lost due to the boil-off phenomenon (Villalba-Herreros et al. 2023). The boiled-off hydrogen vapor must be prevented from being released into the atmosphere as soon as its pressure exceeds the limit of the tank. The storage of the excess boil-off would require extra space for the tanks, and a complete compressor system would have to be added on board to re-use this amount (Yang et al. 2023).

The boil-off effect during transport restricts the maximum sailing time, and therefore the maximum sailing distance. The European Commission's science and knowledge service found that its preferred shipping distance lies between 2,500 and 16,000 km (Ortiz-Cebolla et al. 2021). This covers the shipping route between the Netherlands and Saudi Arabia (Yang et al. 2023). When distances are shorter than 2,500 km, pipelines are a suitable transport mechanism.

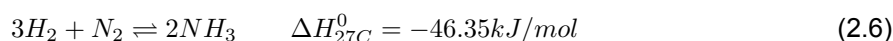
2.2.4. Ammonia

Ammonia is already used as a feedstock in the chemical industry and is increasingly recognized as a promising hydrogen carrier for storage and long-distance transport in the future, or it can be used as a fuel in the shipping sector. Many characteristics of ammonia make this substance a suitable hydrogen carrier, it has a high hydrogen density, and at normal temperature and pressure it is a gas, but it can be easily liquefied at -33°C . Ammonia is a compound of nitrogen and hydrogen and therefore does not generate CO_2 emissions when combusted (IEA 2019a). The hydrogen volumetric density of ammonia is 107 kg/m^3 , and the gravimetric density is 17.6 wt.% (Morris et al. 2021).

The drawback of using ammonia as a hydrogen carrier is its toxicity and it can cause air pollution because it forms particulate aerosols in the atmosphere. It can also affect human health or affect soil and water quality (Weichenhain 2021).

Ammonia production

Ammonia is mainly produced by the Haber-Bosch process, which reacts hydrogen and nitrogen to synthesize liquid ammonia (Weichenhain 2021). About 85% of the total production worldwide is produced by this conventional process, but it is also possible to produce ammonia by water electrolysis. The ammonia synthesis occurs according to equation 2.6. This is an exothermic reaction (negative enthalpy change), and it occurs spontaneously at low temperatures (negative entropy change) (M. Aziz et al. 2020).



The reaction should be performed at a relatively high temperature and pressure of $400\text{-}500^{\circ}\text{C}$ and 10-30 MPa, with the assistance of an iron-based catalyst. To bring the reaction under this high temperature and pressure, about 30 MJ/kg- NH_3 of energy is required (M. Aziz et al. 2020).

The traditional Haber-Bosch process is usually connected to a steam methane reforming process, which delivers hydrogen as a reactant. A sustainable alternative is electrolysis which provides the possibility of generating green ammonia. Green ammonia is produced by electrolysis of water and nitrogen separated from the air with the Haber-Bosch process using renewable energies (Kojima et al. 2022).

Ammonia storage and transport

After the Haber-Bosch process, liquid ammonia can be stored and transported in refrigerated tanks (Weichenhain 2021). The most conventional way to store and transport large amounts of ammonia is in its liquid form (Yang et al. 2023). Options for transporting and handling this substance are already mature (Weichenhain 2021).

Ammonia is a global commodity, and infrastructures for its storage and transportation already exist worldwide. This evidence could enable the early accelerated adoption of large-scale application of NH_3 as an energy carrier. There are 38 and 88 ammonia import and export ports, respectively, including 6 ports that both export and import ammonia. Cargo tankers dedicated to ammonia marine transport are also quite common and similar to the ones for LPG products due to the similarities between the two carriers (Spatolisano, Pellegrini, et al. 2023).

Storage of ammonia is straightforward at atmospheric pressure and at -33°C , or at ambient temperature and 8 bar. Storage of liquid ammonia is not very energetically expensive (Dias et al. 2020). Two main types of storage tanks are available for ammonia storage: isothermal tanks and spherical pressure tanks (Spatolisano, Pellegrini, et al. 2023).

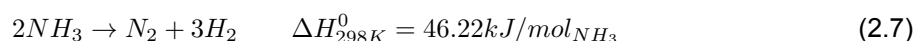
Requirements for shipping hydrogen in the form of ammonia are much more convenient than shipping LH_2 . The shipping at atmospheric pressure and only -33°C or at 25°C and 10 bar is well developed and has already been applied for ≥ 100 years. With the support of a mature infrastructure, the amount of ammonia by sea worldwide is already 17.5 million tons per year (Yang et al. 2023).

Ammonia cracking

In applications where ammonia is used as a storage mechanism for hydrogen, the ammonia will need to be 'cracked' back into hydrogen and nitrogen (Morris et al. 2021). The cracking of ammonia is an endothermic process (Weichenhain 2021).

During the cracking process, the liquid ammonia is pressurized and heated until it evaporates. The ammonia gas is fed into a cracking reactor where it is split back into its elements (Spatolisano, Pellegrini, et al. 2023). Downstream the reaction stage, the separation of the hydrogen product from the unconverted ammonia and nitrogen is performed via pressure swing adsorption (PSA). Then the recovered hydrogen is cooled down again and purified. The heat duty required for the cracking reaction is supplied by burning part of the fed ammonia. No external fuel is needed since ammonia combustion with air is used to sustain the endothermicity of the cracking reaction. Air is used as an oxidizer to ensure complete combustion. (Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024). Around 80% of the ammonia is converted into hydrogen, 20% is used to run the process (Spatolisano, Pellegrini, et al. 2023).

As already mentioned, ammonia decomposition to hydrogen is an endothermic process, as can be seen in reaction 2.7. This reaction can occur with or without a catalyst and is favored at high temperatures and low pressures (Spatolisano, Pellegrini, et al. 2023).



(Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024) states that the energy consumption of the ammonia cracking process is 16.7 kWh/t_{H₂} delivered. This energy consumption only consists of electrical energy and excludes the thermal energy required for the cracking process which is supplied by burning part of the ammonia.

2.2.5. LOHC

Another method to store hydrogen at ambient conditions is with a Liquid Organic Hydrogen Carrier (LOHC). LOHCs are potentially cheap, safe, and easily manageable. Moreover, they allow for long-term energy storage without boil-off or other hydrogen losses as well as uncomplicated transportation. The storage concept of hydrogen within a LOHC is typically based on reversible hydrogenation and dehydrogenation of carbon double bonds (Niermann et al. 2019). Moreover, they can be easily handled with existing infrastructures for oil products (Spatolisano, Restelli, et al. 2024).

The technology consists of two processes, the hydrogen-lean LOHC- and hydrogen-rich LOHC+, which can be transported using the existing infrastructure like pipelines and trucks (Rao et al. 2022).

A variety of cyclic hydrocarbons could serve as LOHCs. These include benzene/cyclohexane, toluene/methylcyclohexane, naphthalene/decalin, biphenyl/bicyclohexyl, and dibenzyltoluene/perhydrodibenzyltoluene (He et al. 2015). Showing the highest technology readiness level (TRL), toluene can be defined as the benchmark for LOHCs. However, despite its maturity and the advantage of large availability at low cost, the main drawback associated with toluene as a hydrogen carrier is the benzene co-production within the dehydrogenation reaction, leading to toxicity issues. To overcome this disadvantage, dibenzyltoluene (DBT) (hydrogenated form: perhydrodibenzyltoluene (H18-DBT)) was proposed by Hydrogenious and it is now under evaluation for implementation at large scale (Spatolisano, Restelli, et al. 2024). This LOHC is used in this study, and since the 1960s widely used as heat transfer fluid (Dürr et al. 2021).

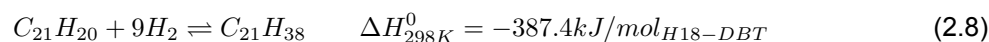
The DBT/H18-DBT system has several advantages for LOHC applications, including high hydrogen storage capacity, low toxicity, and thermal stability. Furthermore, hydrogenation of DBT using hydrogen containing gas mixtures is possible with suitable catalysts. This is attractive for large-scale applications as it connects seamlessly with industrial processes which produce hydrogen-containing gas mixtures (Abdin et al. 2021). The LOHC system H0-DBT/H18-DBT offers a hydrogen capacity of up to 6.2 wt%, corresponding to a volumetric hydrogen content of 56 gH₂/L (Dürr et al. 2021).

LOHC hydrogenation

During the hydrogenation process, the double bonds are saturated with hydrogen. Hydrogen is chemically bound to liquid compounds so that it can be transported at atmospheric pressure (Weichenhain 2021). This process is exothermic and typically takes place at elevated temperatures and pressures (Niermann et al. 2019).

The hydrogenation of H0-DBT is a step-wise consecutive reaction. The first step is the hydrogenation consisting of one outer benzyl ring to form H6-DBT, followed by the hydrogenation of the second outer benzyl ring to form H12-DBT. In the final and rate-limiting hydrogenation step, the middle ring is hydrogenated to form H18-DBT (Dürr et al. 2021).

According to the literature of (Spatolisano, Restelli, et al. 2024), the hydrogenation reactor operates at a pressure of 35 bar and a temperature of 210°C, and the corresponding reaction for dibenzyltoluene is shown in equation 2.8. A catalyst for increased performance is required (Melcher et al. 2021).



Hydrogenated LOHCs do not incur hydrogen losses, which allows for long storage of large volumes (Weichenhain 2021). The next Section covers literature on the storage and transport of LOHCs.

LOHC storage and transport

LOHCs can be stored for an extended period at a large scale without any losses. The idea of using LOHCs for large-scale stationary hydrogen storage is still relatively new. However, hydrogenation of aromatics and dehydrogenation of cyclic hydrocarbons is performed at a large scale in industrial applications, for example in oil refineries. Thus, LOHC compounds, along with circular hydrogen carriers, could be potential candidates for stationary hydrogen storage at a large scale using the well-established infrastructure (Abdin et al. 2021). An additional reason why long-term storage is suitable for LOHCs, is that hydrogenated LOHCs do not incur hydrogen losses, (Weichenhain 2021).

Due to the compatibility of LOHC storage and transport with existing infrastructure for fossil fuels, it is also relatively easy to use existing vessels with minor modifications (Schuler et al. 2024). When in a transport scenario, hydrogenation and dehydrogenation take place at different sites, because of this heat integration is a key issue of an efficient hydrogen transport cycle. Another key issue of this reaction scheme is that the release of hydrogen only takes place when heat and a suitable catalyst are present (Melcher et al. 2021).

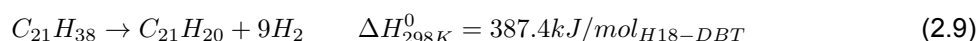
On the logistics side, it becomes obvious that the main difference between LOHC and other hydrogen transport solutions is the fact that there is a carrier that can be loaded and unloaded. The empty carrier, which is the dehydrogenated LOHC, needs to be transported back to the place of hydrogenation. This empty carrier is hydrogenated again when arriving back at the location (Yang et al. 2023). This also requires storage facilities for loaded and unloaded hydrogen.

LOHC dehydrogenation

After transport, the hydrogen can be released again in its pure form by dehydrogenation. This process is based on a catalytic endothermic reaction taking place mostly close to atmospheric pressure and elevated temperatures (Niermann et al. 2019).

Since this dehydrogenation reaction is highly endothermic, the heat of the reaction is supplied by burning part of the hydrogen produced (Spatolisano, Restelli, et al. 2024). The dehydrogenation process requires 53-65 kJ/mol_{H₂} depending on the material used (Naseem et al. 2021).

(Spatolisano, Restelli, et al. 2024) describes a hydrogenation reactor for H18-DBT, this reactor works at 320°C and 1.1 bar and the corresponding reaction is shown in equation 2.9.



The energy consumption for the dehydrogenation process consists of 4.14 MWh/t H₂ of cooling energy provided by cooling water, 17.1 MWh/tH₂ of heat provided by burning part of the hydrogen, and 3.23 MWh/t H₂ of electrical energy. This high energy requirement is a limiting factor for the hydrogen release (Rao et al. 2022). According to (Spatolisano, Restelli, et al. 2024), the amount of hydrogen burned for the reaction amounts to 36%.

2.3. CO₂

The Dutch Climate Agreement has given carbon capture a significant role in reducing CO₂ emissions from industry. With an annual emission reduction of 7 megatons (Mton) by 2030 out of a total of 50 Mton, this industry will provide roughly half of the total industry reduction. This potentially makes carbon capture the largest emissions reduction technology in The Netherlands after wind and solar power (Akerboom et al. 2021). In this study, the CO₂ is captured and further used for the production of methanol. Carbon capture and utilization (CCU) refers to a range of applications through which CO₂ is captured and further used (IEA 2023a).

Biogenic CO₂ is essential as a feedstock to produce E-methanol. The required CO₂ can be captured from various sources, including power plants and industrial exhaust streams. However, to be classified as renewable and sustainable, it must originate from biomass combustion or waste biomass, distilleries, and biogas (IRENA 2021b).

The CO₂ capture from these sources currently still happens at a small scale and needs to be expanded in the future. The production of E-methanol from renewable CO₂ sources, especially the least expensive but most limited ones, might also be in competition with other carbon capture, use, and storage applications. Ultimately, the capture of CO₂ directly from air (DAC) offers the largest potential, but its costs need to decrease substantially to be attractive to use (IRENA 2021a).

In principle, if biomass is grown sustainably and then processed into a fuel that is then burned, the technology pathway can be considered carbon-neutral. If some or all of the CO₂ released during combustion is captured and stored permanently, it is carbon-negative (IEA 2020).

In this study, CO₂ is either directly utilized for methanol production in scenario 2 or liquefied for transportation in scenario 1. This section details the various components of CO₂ handling considered in this research. The capture technology itself is out of the scope of this research and, therefore, only briefly mentioned in this literature review.

2.3.1. CO₂ capture

CO₂ capture technologies in various forms have already been deployed for almost a century (Monteiro et al. 2024). This technology could be a choice in hard-to-abate industries that lead to reductions in greenhouse gas (GHG) emissions. The main carbon capture technology options used are (Hong 2022):

- **Post-combustion capture** this technology captures CO₂ from flue gases after the combustion stage (Monteiro et al. 2024)
- **Pre-combustion capture** This technology includes the pre-reformation of fuels to produce a mixture of hydrogen and CO₂, where hydrogen can combust with air after the CO₂ is captured (Monteiro et al. 2024)
- **Oxy-fuel combustion capture** This technology captures CO₂ after the combustion of fuels with purified oxygen (Monteiro et al. 2024)
- **Chemical looping combustion** This technology generates two flue gas streams: one from the air reactor, almost free of CO₂, and another one from the fuel reactor, which mainly consists of CO₂. The air reactor stream can be released into the atmosphere, causing minimal CO₂ pollution. The other stream contains almost all of the generated CO₂ by the system (Ishida et al. 1997).
- **Direct air capture (DAC)** This technology directly separates CO₂ from the air or the sea (Erans et al. 2022).

The International Energy Agency (IEA) projects that by 2050, 7.6 Gt of CO₂ will be captured annually in the energy industry to meet Paris climate goals (Bouckaert et al. 2021). In hard-to-abate industries, carbon capture is crucial for emissions reduction, contributing 27% of reductions by 2060, with significant contributions from cement, iron, steel, and chemicals sectors (IEA 2019b). Despite limited implementation, carbon capture technology has the potential to significantly reduce industrial GHG emissions through either underground storage or utilization as feedstock for other processes (Rissman et al. 2020).

CO₂ market

The cost of capturing the CO₂ needed to make synthetic fuels is a major component of the total cost of making those fuels (IEA 2020). The cost of carbon capture is influenced by many factors, including the CO₂ source, capture technology, process type, as well as volume. In 2023, CO₂ capture costs are projected to range from USD 20-25/tCO₂ for processes with concentrated CO₂ streams to USD 37-111/tCO₂ for diluted gas streams (IISD 2023).

Various cost comparisons are available in the literature for a lot of different capture technologies, though future costs are highly uncertain since this family of technologies is at a comparatively early stage of development (IEA 2020).

For example, for hard coal, capture costs vary by method. Post-combustion capture costs about 47 USD/tCO₂, while pre-combustion capture is around 56 USD/tCO₂. The International Energy Agency (IEA) reports an average capture cost of 58 USD/tCO₂ for post-combustion and 43 USD/tCO₂ for pre-combustion systems. These discrepancies highlight the difficulty in comparing capture systems due to differing boundary conditions. Generally, recent studies suggest that post-combustion capture tends to have lower capital costs and cost of electricity without capture (Zahid et al. 2014).

Biogenic CO₂ is the CO₂ captured in the production of bio-fuels such as bio-ethanol or during the production of electricity at biomass-fired power plants or biomass waste power plants. It is expected that the use of CO₂ as a feedstock will grow and that the contribution of biogenic CO₂ will increase a lot, as can be seen in Figure 2.8. By 2070, 45% of all the CO₂ used is captured from biomass power or bio-fuel production plants (IEA 2020).

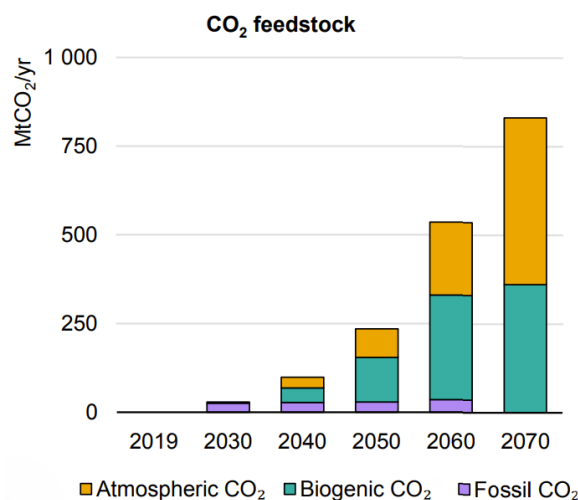


Figure 2.8: Global CO₂ use as feedstock for synthetic fuels (IEA 2020)

A study from (IEA 2020) shows an expected range of biogenic CO₂ capture costs of 15-85 USD/t CO₂. This study also states that it is expected that in the category of biogenic CO₂, the CO₂ generated from the production of bio-ethanol is expected to be the cheapest source of biogenic CO₂ and will be available at around 15-30 USD/t CO₂ by 2030.

The literature of (Aromada et al. 2022) simulates the impact of different parameters on CO₂ capture cost in Rotterdam. The base case of Aromada's study evaluates a CO₂ capture cost of 65 €/ton for 2019. By changing different parameters in his study, a range from 62.9 to 84.5 €/ton resulted.

A report from the Dutch government states that the cost of capturing CO₂ for post-combustion capture from existing waste or biomass power plants for 2024 is 220 €/ton CO₂. This price also includes the preparation for liquid transport, which is the reason for this relatively higher value (Lensink et al. 2024).

(Beiron et al. 2022) provides a techno-economic assessment of carbon capture applied to 110 existing Swedish biomass and waste-fired combined heat and power plants (CHP). They conclude that the estimated specific cost of CO₂ capture and transportation via truck to a storage hub is in a range of

45-125 €/t CO₂ for most CHP plants. When excluding the transport and storage, capture at a cost of <100 €/t CO₂ could be available.

The work of (Karlsson et al. 2024) evaluates a model over the period of 2025-2050, and indicates that a CO₂ price of around 80 €/t CO₂, excluding the cost of storage, provides a sufficient economic incentive for the large-scale implementation of carbon capture technologies.

2.3.2. CO₂ liquefaction

CO₂ can be liquefied at various pressures between the triple point (5.2 bar, -56.6 °C) and the critical point (73.8 bar, 31.1 °C)(Span et al. 1996). Conditions near the triple point are relatively low pressure and relatively low temperature, whereas conditions near the critical point are relatively high pressure and relatively high temperature. Liquefying CO₂ near the triple point requires a large refrigeration system because of the lower temperature than other liquefaction pressures. In contrast, a massive compression system is necessary near the critical point. The density of liquefied CO₂ decreases as its pressure approaches the critical point. Thus, CO₂ liquefied near the critical point has a disadvantage in transportation because of its lower density (Seo et al. 2016).

There are basically two processes in practice to compress and liquefy CO₂ commercially (Zahid et al. 2014):

- Low-pressure process making use of an external refrigeration system to achieve required cooling for condensation of the gaseous CO₂ after it is dried and compressed to about 17 bar.
- High-pressure compression with free liquid expansion. This process uses self-refrigeration to liquefy the CO₂ that is compressed beyond the critical point.

To be economically favorable for large-scale transport of CO₂ by ship after liquefaction, the CO₂ should be liquefied and transported at semi-pressurized pressure near the triple point. e.g. at 6.5 bar and -52°C (Aspelund et al. 2005).

The 'low pressure' and 'high pressure' process designs can be divided into ones that use an external refrigeration system (so-called "closed" systems) and ones that cool the CO₂ solely by compression and expansion, without the use of an external refrigerant ("open" systems or "integrated" refrigeration) (Durusut et al. 2018).

According to (Zahid et al. 2014), the energy requirement is 97.3 kWh per tonne of CO₂ for a liquefaction unit. This liquefaction energy only consists of electrical energy.

2.3.3. Liquid CO₂ storage and transport

While the flow of CO₂ from a source such as a power plant or industrial emitter, and the subsequent liquefaction, is continuous, the shipping occurs in discrete runs and is a batch process. An intermediate buffer storage is therefore needed to store the CO₂ when there is no ship in the port (Durusut et al. 2018).

Depending on the availability of land close to the exporting CO₂ harbor, the liquefied CO₂ could be stored either onshore or on a floating facility (Yoo et al. 2013). Unlike in the case of poisonous or highly flammable gases, CO₂ can be released into the air in case of delays and thus the storage does not have to be sized based on extraordinary incidents. It is usually assumed that the design and specifications of the storage tanks on board the ship are similar or identical to those of the tanks that are used for the temporary buffer storage onshore (Seo et al. 2016).

A variety of classes of steel are used for the storage tanks, depending on the pressure and temperature of the CO₂ (Durusut et al. 2018). Transporting CO₂ as a liquid requires pressures above 5.2 bar to prevent it from transitioning into a gaseous or solid state. Semi-pressurized ships maintain CO₂ in the liquid phase by operating at pressures between the triple point (5.2 bar) and the critical point (73.8 bar). Operating closer to the triple point allows for higher transport capacities and lower vessel production costs. However, operational challenges, such as the risk of dry ice formation, must be carefully managed (Aspelund et al. 2005).

Fully pressurized transport of CO₂ in the liquid phase at ambient temperatures is less desirable due to high pressures near the critical point, leading to costly vessel production and operational challenges.

Semi-pressurized transport near the CO₂ triple point offers a more efficient and cost-effective solution for large-scale CO₂ transportation but requires careful management of dry ice formation. At this pressure, the technology and experience from building and operating conventional LPG tankers can be utilized, and large pressurized cargo tanks can be produced in an economical way (Aspelund et al. 2005).

To address the current CO₂ transport situation, small-scale semi-pressured ships are currently operating around the North Sea. Their transport pressure is 14–20 bar, and their CO₂ transportation capacity varies between 1000 and 1500 m³. These ships are not suitable for transporting large amounts of CO₂, and the pressure needs to be decreased to increase the vessel size. Commercially available large-capacity tanks are usually operated within the pressure range of 5–7 bar, and several studies indicate that 6.5 bar is a feasible pressure for CO₂ ship transportation. It is also the operating pressure of the intermediate storage terminals that links the continuous liquefaction process to discrete ship transportation (Lee et al. 2012).

2.3.4. CO₂ reconditioning

For further use of the CO₂ for the methanol synthesis, the CO₂ temperature and pressure condition must be suitable for the reactor. This process of reaching this condition is called gasification (Durusut et al. 2018). Reaching these conditions consists of pumping to reach the desired pressure, followed by heating to increase the temperature (Roussanaly et al. 2021).

Compressing liquid CO₂ using pumps requires much less energy than compressing gaseous CO₂ using compressors due to the significantly smaller specific volume of liquid CO₂ (Alabdulkarem et al. 2012). The energy requirements for pumping and heating CO₂ vary depending on the injection condition as well as the transport condition. It is usually assumed that seawater is used in the heat exchanger to heat the CO₂ (Durusut et al. 2018).

In the case of onshore unloading, the gasification happens onshore after the unloading from the ship to the temporary storage (Seo et al. 2016). According to the literature of (Bjerketvedt et al. 2020), the energy consumption for the reconditioning process at low pressure is 6.14 kWh/ton_{CO₂}.

This literature review offers a comprehensive analysis of the various components within the E-methanol value chain examined in this study. A substantial body of literature exists on these components, with most technologies already achieving mature levels. Despite numerous studies detailing the value chains and handling processes for methanol, CO₂, and hydrogen in their respective forms, there is currently no study that integrates all these elements while considering the trade dynamics in two different routes between Saudi Arabia and the Netherlands.

2.4. Research gap

This thesis contributes to the scientific literature by defining and subsequently addressing a research gap that is based on information provided in the literature review in this Chapter. The identification of this gap underscores the relevance of this study. This section explains the research gap and summarizes key findings from the literature review.

The literature review presents a comprehensive review of all the components considered in the value chain of E-methanol. It focuses on the conversion, storage, transport, and reconversion techniques of methanol and its feedstocks: hydrogen and CO₂.

Section 2.1 covers the current state of the methanol industry, focusing on its properties, production methods, and logistical handling. Currently, this industry heavily relies on fossil fuels, but the shift towards renewable methanol is promising. The storage and transport of methanol are relatively straightforward, utilizing existing infrastructure designed for oil and gas substances. Sections 2.2 and 2.3 address the feedstocks necessary for methanol production. Section 2.2 discusses the challenges associated with hydrogen mobility and various applications to mitigate these issues. Section 2.3 elaborates on CO₂ which is captured and its utilization.

The literature review highlights the importance of transitioning to renewable methanol to reduce CO₂ emissions in the chemical sector. While the review provides extensive details on the individual components of the E-methanol value chain, and various studies are analyzing value chains of methanol,

hydrogen in different forms as well as CO₂, it reveals a lack of comprehensive studies that integrate these components and value chains and compare different routes, including shipment, into a single optimized value chain specifically for the Netherlands, with hydrogen sourced from Saudi Arabia.

The primary research gap is the absence of an integrated techno-economic analysis that considers the inter-dependencies of all components within the E-methanol value chain, along with the trade dynamics between Saudi Arabia and the Netherlands.

This study aims to fill this knowledge gap by evaluating E-methanol value chain configurations for methanol availability in the Netherlands and examining supply strategies through the development of two comparative scenarios. The analysis covers both technical and economic perspectives, enabling a well-informed decision regarding the optimal method for supplying methanol to the Netherlands. The proposed methodology for this techno-economic analysis is extensively described in Chapter 3.

3

Methodology

In this section, the methodology employed to develop the model aimed at addressing the research question presented in Chapter 1 is outlined. This study uses a conceptual process design methodology, and the model is built to determine the optimal logistics for an E-methanol value chain to ensure methanol availability in the Netherlands. To achieve this objective, a comprehensive techno-economic assessment is required.

It is important to note that part of the data utilized in this study is derived from existing and historical operating assets available in the literature. This provides a solid foundation based on proven performance and established benchmarks. However, given the conceptual nature of this process design, and the current evolving technologies in the renewable sector, certain data used in this study relies on projections and expectations for future performance and innovations. This blend of empirical data and forward-looking assumptions aims to provide a comprehensive and realistic analysis, acknowledging the inherent uncertainties.

Initially, the general methodology applied to the various components of the value chain is described. Subsequently, each component of the value chain is examined in detail, with an extensive explanation of how the techno-economic inputs for the model are obtained. This systematic approach ensures that all relevant factors are considered, providing a robust basis for the model's development and its subsequent application to the research question.

Two different scenarios have been drawn up for setting up the methanol value chain, and they are compared from a technical and economic point of view. The methanol produced in both scenarios is considered E-methanol. Both scenarios consider the exchange of feedstocks or products between two countries. Regardless of what is exchanged between these two countries, a port-to-port shipping configuration is assumed. It is assumed that the methanol is delivered to the Port of Rotterdam in the Netherlands and distributed across the country and the rest of Europe. It is also assumed that the production and storage units considered are situated near the loading/unloading facility in the Port of Rotterdam, which means that it is assumed that road transport after shipping isn't necessary in any of the scenarios. Saudi Arabia is assumed to be the country that produces the hydrogen needed for methanol synthesis.

The availability of high solar yields and abundant land provides excellent conditions for green hydrogen production in this region. Abundant funding, direct decision-making, and existing infrastructure position Saudi Arabia as an excellent hydrogen first-mover (Ansari 2022). Saudi Arabia has abundant renewable energy potential and significant natural gas resources. Thus, it is uniquely positioned to produce both green and blue hydrogen at the most competitive rates in the world. It can also help other countries achieve their decarbonization goals by exporting hydrogen. Moreover, in 2021 the Minister of Energy from Saudi Arabia announced the goal of becoming the world's largest hydrogen producer (Hasan et al. 2021). Therefore, the hydrogen produced in Saudi Arabia is used for the methanol production in this research.

The Jeddah Islamic Port in Saudi Arabia is assumed to be the specific port used in this study. Production and storage units are assumed to be near the loading/unloading facility in the Port of Jeddah, implying that no road transport between the port and the storage facility is needed after shipping. The Jeddah Islamic Port is situated on the Red Sea coast of Saudi Arabia and is the country's busiest port. Jeddah Port is also called the country's commercial capital and the primary port serving the cities Mecca and Medina (Bhattacharjee 2022). Transport between these two ports is assumed to be a direct connection via the Suez Canal, which has a distance of 7,500 km. The route traveled by the vessel is shown in figure 3.1.

(Siroky et al. 2016) analyzed the economic effectiveness of operation and utilization of large carriers and stated that the fuel consumption from container ships is exponentially growing at speeds higher than 14 knots (26km/h). Although the vessels used in this study are smaller than typical container ships, it is assumed that their operating speeds are comparable to the optimal speed of a container ship. Therefore, the vessels used in this study are cruising at a speed of 26 km/h, which results in a cruising time of ≈ 13 days from port to port.



Figure 3.1: Shipping route between the Port of Jeddah (SA) and the Port of Rotterdam (NL) considered in this study

3.1. Model overview

This section provides a comprehensive overview of the model constructed in this study, detailing the included components. For each component, the Levelized Cost of Methanol (LCOM) is calculated to facilitate the comparison of different routes considered in the model. Figure 3.2 presents the considered parameters and the steps performed for each component.

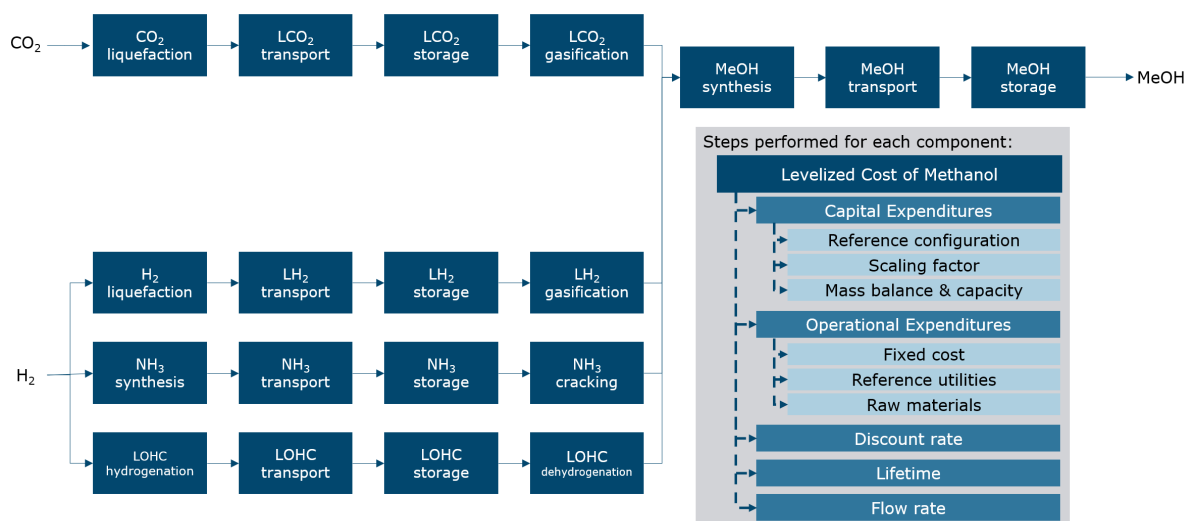


Figure 3.2: Overview of the model used for the comparison in this research. For each component, the same steps are performed which are shown and summarized in the grey square.

3.1.1. Summary of assumptions

This Section summarizes all the assumptions made for the base case considered in this research. The details and rationale behind the assumptions can be found in the following sections.

- The annual methanol production capacity equals 200 kt/yr
- The methanol produced is classified as E-methanol
- Hydrogen is sourced from Saudi Arabia
- CO₂ is captured from installations in the Port of Rotterdam
- Import and export is done between the Port of Rotterdam (NL) and the Jeddah Islamic Port (SA) over a distance of 7,500 km
- Economic prices are in 2024 EUR
- All conversion units operate continuously
- All vessels are cruising with a speed of 26 km/h
- Shipment is conducted from port-to-port
- Transportation relies primarily on shipping, and no road transport is needed: production and storage sites are near terminals' loading and unloading sites
- The economic lifetime is the same for all components considered in the value chain and equals 20 years with a construction period of 3 years and a discount rate of 10%
- The technologies of hydrogen and CO₂ production are out of the scope, the costs associated with producing these feedstocks are assumed to be equivalent to their market purchase prices

3.2. Technical and economic methodology

To formulate an answer to the research question, this thesis is based on the approach of a techno-economic analysis (TEA). This is a method where technology and economics are combined by assessing technological quality and economic feasibility (Lauer 2008). Within the scope of this research, TEA is essential to evaluate both scenarios and make a comprehensive decision.

A generalized methodology is applied to analyze each configuration within the value chain comprehensively. This process begins with the assumption of a target annual methanol production volume of 200 kt. A production capacity of 200 kt per year allows for economies of scale, reducing per-unit costs as production increases while remaining manageable in terms of investment and operational risk. This

capacity aligns with the current and anticipated methanol demand in the European market, which can be served efficiently from the Netherlands.

Following this, the production quantities for other components within the value chain are determined using a bottom-up approach. This approach involves calculating the required quantities of each upstream component based on the final production rate of methanol. By working backward from the end goal, this method ensures that all intermediate production stages are aligned with the assumed annual production volume, thereby facilitating a coherent and integrated analysis of the entire value chain. This approach provides a robust foundation for a detailed examination of each configuration, ensuring that all relevant variables and interdependencies are thoroughly considered.

Finally, sensitivity analyses are done by varying parameters in the value chain and observing their effect on the outcome. By doing a sensitivity analysis, the parameters having the most impact on the outcome can be identified.

3.2.1. Technical methodology

The technical inputs for the model considered in this study encompass several critical factors, including mass balances, unit capacities, and various types of energy consumption associated with each component of the value chain. These inputs are essential for accurately optimizing the logistics of the E-methanol value chain.

A thorough review of the literature is conducted to determine the values for each of these technical parameters, which involves identifying and extracting relevant data. The mass balances are calculated to ensure that the input and output flows of materials within each unit are accurately represented, maintaining consistency with the principles of conservation of mass. Unit capacities are assessed to understand the maximum processing capabilities of each component, which is crucial for identifying potential bottlenecks and optimizing throughput. Additionally, the energy consumption profiles for each unit are examined to quantify the various forms of energy required, including electrical and different kinds of thermal energy.

By leveraging data from established literature, these technical parameters are validated and used as reference points, ensuring that the model reflects real-world conditions. Subsequent subsections thoroughly explain the specific methodologies and approaches used to evaluate the various technical parameters.

Mass balance and capacity

To ensure the accurate modeling of input and output flows within the conversion units, detailed mass balance ratios have been calculated for various types of production units based on literature. These mass balance ratios are critical for maintaining consistency with the principles of mass conservation, ensuring that all material flows within the system are accurately accounted for.

The production capacities of the conversion units are derived based on mass balances, ensuring that the input and output material flows are accurately accounted for within each unit. Starting at the end of the chain with a capacity of 200 kt methanol and using the mass balance of each unit, the capacities of the previous units in the chain are derived by working backward. This assumption allows for a consistent and standardized approach to modeling the throughput and operational capabilities of the conversion units.

For the storage and transport components of the value chains, it is essential to determine appropriate capacities for storage tank volumes and transport vessels. These capacities are critical for accommodating the projected production volumes and ensuring the smooth operation of the logistics chain. The selection of these volumes is conducted by a thorough analysis of existing literature on current operational configurations and future conceptual plans. This ensures that the chosen capacities for storage and transport components are aligned with anticipated industry developments.

The capacities of vessels and storage tanks used in this study are derived from typical sizes reported in the literature for considered substances, reflecting both existing and planned shipping and storage projects depending on the maturity of the technology.

Energy consumption

Energy consumption is a critical parameter for each conversion unit analyzed in this study. The provided energy consumption values are standardized by converting them into a format that expresses energy consumption per unit of production volume for the specific product in question. This standardized metric allows for a more precise and comparable analysis across different units and configurations.

The energy consumption analyzed in this study encompasses various forms of energy: electrical energy and different types of thermal energy, such as heat, cooling (using cooling water), cryogenic, and refrigerant. To calculate the specific energies of a conversion unit, the standardized energy consumption value is multiplied by the assumed production rate for that unit. This calculation ensures that the energy requirements are accurately scaled according to the expected production output, and this approach ensures that all energy consumption metrics are consistently and accurately represented.

3.2.2. Economic methodology

Item	Value
Discount rate	10%
Project lifetime	20 yr
Construction period	3 yr
Exchange rate (2024)	0.941 €/US\$
Plant availability	continuous (8760 h/y)

Table 3.1: Financial assumptions for LCOM calculation

The economic parameters considered in this study are summarized in Table 3.1. Conducting the parameters for the economic assessment includes several key factors for a comprehensive analysis. The lifetime and discount rate of the entire value chain need to be determined, and the CAPEX and OPEX for each component of the chain need to be calculated. Together, these parameters will represent the final levelized cost of methanol, providing a standardized measure to compare the scenarios.

Conceptual or previously implemented values are sourced from the literature to determine the values of these economic parameters. These values are then adjusted according to established economic scaling rules to reflect the current year, the European currency, and the desired capacities. This process ensures that the economic parameters are accurately scaled and contextualized to provide a robust basis for the economic assessment. By incorporating as possible up-to-date and region-specific data, the analysis maintains relevance and accuracy, allowing for a comparative evaluation of the value chain's economic viability.

In this study, the conceptual process design methodology is applied. The associated accuracy for this type of methodology is expected to be 50-100%, which is assumed acceptable for studies in the conceptual phase.

Economic lifetime and discount rate

The economic lifetime refers to the period over which the infrastructure and equipment involved in the value chain are expected to be operational and economically viable. For this study, an economic lifetime of 20 years is chosen, with a construction period of 3 years. This selection is based on the following considerations:

- According to the (IEA 2019a), the typical economic lifetime for renewable energy projects, including those involving chemical processes, ranges from 20 to 25 years.
- Various studies present in literature have reported a lifespan that can exceed 20 years with proper maintenance and technological updates.

The discount rate is a critical parameter that reflects the time value of money, the opportunity cost of capital, and the risk associated with the investment. Based on a discussion with Power2X, a discount rate of 10% has been chosen. This is a commonly used average discount rate, and selecting an average discount rate is a widely accepted practice, particularly when assessing a value chain comprising multiple diverse components. It is assumed that the plants considered in this research operate continuously, so the plant availability for each plant is 8760 hours per year.

CAPEX

To determine the Capital Expenditure (CAPEX) values for each component of the value chain, a systematic approach is employed. This process involves utilizing reference values for CAPEX from similar configurations and then adjusting these values to suit the specific requirements of the current units. The steps in this methodology include:

- **Obtaining reference CAPEX values sourced from existing literature** These reference points provide baseline costs for similar components and configurations within the chemical process and renewable energy sectors.
- **Scaling to desired capacities with the six-tenths rule** This rule is commonly used in the chemical industry as a practical approach for estimating the costs of equipment and facilities when scaling up or down from known data. Although this method is commonly used, it is mainly suitable for scaling to numbers that are approximately the same order of magnitude.

This rule is particularly useful when the cost of a similar item of a different size or capacity is known, and represented by 3.1 (Whitesides 2012). Here, C_A and C_B are the costs of the original and scaled item, respectively, and V_A and V_B are their capacities. The exponent 0.6 represents the economy of scale, indicating that costs do not increase linearly with size but at a decreasing rate.

$$C_B = C_A \cdot \left(\frac{V_B}{V_A}\right)^{0.6} \quad (3.1)$$

While the six-tenths rule is broadly applicable, its accuracy can vary depending on specific circumstances and equipment types. Nevertheless, in this study, it is assumed that the six-tenths rule is used for all cost scaling calculations. This assumption is justified by the rule's widespread acceptance and its ability to provide reasonably accurate estimates with limited initial data.

- **Adjusting the cost value to inflation according to CEPCI** The Chemical Engineering Plant Cost Index (CEPCI) is a crucial tool for professionals in the chemical process industry to adjust process plant construction costs over time. The CEPCI provides a standardized method for adjusting historical costs to current values, ensuring consistency across different projects and periods. This standardization is vital for comparing costs accurately and making informed financial decisions.

The CEPCI is updated monthly, allowing for timely adjustments that reflect the latest economic conditions. In this study, the CEPCI value used for 2024 is the value from February 2024.

To apply the CEPCI for inflation adjustment, equation 3.2 is used. This equation multiplies historical cost data by the ratio of the CEPCI value for the current year to the CEPCI value for the historical year. This adjustment ensures that the cost estimates are current and reflective of present-day economic conditions (Whitesides 2012). The CEPCI values of the past 20 years are presented in Appendix A (Skills 2024).

$$C_B = C_A \cdot \frac{CEPCI_{year,B}}{CEPCI_{year,A}} \quad (3.2)$$

- **Converted to 2024 euros** When the reference CAPEX values are provided in currencies other than euros, these values must be converted to euros as the final step in the CAPEX calculation. The conversion utilizes the average exchange rate for 2024 up to February. Specifically, when converting from USD to EUR for 2024, the value will be multiplied by 0.941. This conversion factor is derived from the exchange rate data provided by [Wisselkoers.nl](https://www.wisselkoers.nl) ([wisselkoers.nl](https://www.wisselkoers.nl) 2024).

The choice of using the average exchange rate up to February 2024 ensures that the conversion reflects recent market conditions, providing a more accurate and relevant financial assessment.

OPEX

To accurately determine the total Operational Expenditure (OPEX) for each component of the E-methanol value chain, the OPEX is divided into fixed and variable components.

Fixed OPEX represents costs that do not vary with the level of production. Based on insights obtained from (Timmerhaus et al. 2004), it is established that fixed OPEX in the chemical process industry typically accounts for 2.4% of the CAPEX. Therefore, this percentage is used for the fixed OPEX calculations in this study.

Variable OPEX, on the other hand, fluctuates with production levels and includes costs associated with utilities such as electricity, water, and raw materials. These expenditures are calculated separately for each component based on the specific utilities required and the prices determined for the different kinds of utilities. These prices are covered in the next section.

Levelized Cost of E-Methanol (LCOM)

The levelized Cost of Product (LCOP) is a common indicator of discounted cash flow analysis, and it represents the product selling price necessary to achieve a net present value (NPV). That is calculated from the value of all sales of the product over the economic plant lifetime to be equal to the present value of construction, maintenance, and operation of the plant (Cameli et al. 2024). Because in this study the 'product' is E-methanol, the Levelized Cost of E-Methanol (LCOM) is used.

Once the fixed and operating costs for each stage of the value chain have been calculated, the levelized cost of methanol (LCOM) [$\text{€}/\text{ton}_{MeOH}$] is calculated. The LCOM is a crucial economic metric used to evaluate the average cost of producing methanol over the considered lifetime, considering all relevant costs. The LCOM is calculated according to equation 3.3.

$$LCOM = \frac{\sum_{t=0}^{N-1} \frac{CAPEX_t + OPEX_t}{(1+r)^t}}{\sum_{t=0}^{N-1} \frac{P_{MeOH,out}}{(1+r)^t}} \quad (3.3)$$

where:

- $P_{MeOH,out}$ is the annual amount of methanol delivered;
- r is the discount rate
- t is the considered year, with $t = 0$ is the 2024 year and $N - 1$ is the end year;
- $CAPEX_t$ and $OPEX_t$ are the capital and operating expenses at time t .

The financial assumptions in the LCOM calculated are listed in Table 3.1. The LCOM calculation is an essential metric for comparing different production technologies and assessing the financial viability of, in this case, methanol production projects.

Uncertainties in conceptual process design

Estimating the investment costs of a new product/process alternative during early-stage design is a challenging task (Cheali et al. 2015). Especially in the field of renewable energy applications, where a lot is still uncertain because rapid technological advancements and the early-stage nature of many renewable technologies lead to limited historical data and frequent changes in cost structures (IEA 2020).

This study is considered a conceptual process design. According to (Cheali et al. 2015), the typical accuracy range of a chemical process design in the conceptual phase ranges from -20 to -50% when underestimated or to +30 to +100% when overestimated.

In this research, an accuracy percentage for CAPEX and OPEX estimates is assumed. This percentage is applied to show the lower and upper ranges of the final LCOM per component. One percentage is chosen for the CAPEX uncertainty and one for the OPEX uncertainty; this gives a range \pm the base case values. In general, CAPEX has a higher uncertainty than OPEX in chemical processes (Chemical Engineering Online 2024).

(Alhamouri et al. 2024) established a range for the accuracy of CAPEX and OPEX by comparing the values from the conceptual design phase to those from the final phase of different chemical plant projects. The results from this evaluation are a CAPEX accuracy in the range of -25% to +150% and an OPEX accuracy in the range of -4% to +12%.

By comparing numbers from the literature of (Cheali et al. 2015) and (Alhamouri et al. 2024), an accuracy margin of $\pm 50\%$ is assumed for CAPEX values, while an accuracy margin of $\pm 10\%$ has been set

for OPEX values. The results of the applied accuracy margins on the base case results can be found in Appendix B.

3.2.3. Cost of utilities and raw materials

Utility	Value	Unit	Reference
Electric energy (NL)	0.094	€/kWh	(Lensink et al. 2024)
Electric energy (SA)	0.075	€/kWh	(Mayer et al. 2023)
Cooling water (NL)	0.0013	€/kWh	(Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024)
Cooling water (SA)	0.00072	€/kWh	(Mayer et al. 2023)
Heat utilities (NL)	0.046	€/kWh	(Lensink et al. 2024)
Heat utilities (SA)	0.018	€/kWh	(Alshammari 2021)

Table 3.2: Cost of utilities (2024 €)

Raw material	Value	Unit
CO ₂	85	€/ton
Hydrogen	4.5	€/kg

Table 3.3: Cost of raw materials (2024 €)

In this study, price assumptions for utilities and raw materials are established. The utilities include price assumptions for electricity tariffs, heat tariffs, and cooling water tariffs in both the Netherlands and Saudi Arabia. These tariffs are based on values from literature adjusted with inflation to 2024. The assumed price tariffs used in this research are listed in Table 3.2.

These assumptions are crucial for our economic models and analyses, accurately reflecting the regional differences and market conditions. The price assumptions of the raw materials CO₂ and hydrogen can be found in Table 3.3 and are elaborated in the subsequent sections.

CO₂ captured

The scope of this research excludes the detailed examination of the carbon capture processes. Consequently, for the purposes of this study, CO₂ captured from renewable energy sources will be considered as a purchased commodity. Therefore, the analysis will include values for both the quantity and the cost associated with the captured CO₂. The quantity is derived from the mass balances of the components considered, as described in Section 3.2.1.

A price in €/ton of captured biogenic CO₂ is quantified. In the literature review in Section 2.3, different prospects on captured CO₂ prices are mentioned. Because this is a conceptual process design, a conceptual price expected for 2030 is assumed for biogenic CO₂ in this study.

(IEA 2020) prospects a range of biogenic CO₂ capture costs of 15-85 USD/t CO₂ by 2030. A case study on capture cost in Rotterdam from (Aromada et al. 2022) results in a range from 63 to 84.5 €/ton for 2019. (Beiron et al. 2022) provides a techno-economic assessment of carbon capture at Swedish biomass and waste-fired combined heat and power plants for 2045 and states CO₂ could be available at a cost of <100 €/t CO₂. The work of (Karlsson et al. 2024) evaluates a model over the period of 2025-2050 and presents a CO₂ price of around 80 €/t CO₂.

Based on the values above, a very large range is mentioned between 15-100 €/t CO₂. The value that is most consistently mentioned in these studies is somewhere around 80-85 €/t CO₂. The studies of (Beiron et al. 2022) and (Karlsson et al. 2024) evaluate carbon capture applied to over 100 existing biomass and waste-fired plants, which makes this a very reliable study. They also state a capture price of around 80-85 €/t CO₂. In a discussion with a Power2X expert, a CO₂ capture price of 85 €/t CO₂ is corresponding with their current view on CO₂ capture pricing.

It is important to acknowledge that predicting the exact future price of feedstocks is inherently uncertain due to several factors, such as technological advancements and market dynamics. These uncertainties

make this parameter particularly suitable for sensitivity analyses in subsequent phases of this study.

The CO₂ capture in this study in the base case is chosen to be 85 €/t CO₂ as shown in Table 3.3. This choice is justified by frequent mention in credible studies and the insights from Power2X.

Green hydrogen

Since hydrogen production is beyond the scope of this study, it is assumed that the hydrogen required for methanol production will be purchased in gaseous form at 30 bar as a feedstock on the market. Consequently, a price in €/kg is assumed for hydrogen sourced from Saudi Arabia. This price includes only the cost of production via electrolysis and is based on an evaluation of prices reported in the literature.

In the literature review in Section 2.2, different prospects for LCOHs of green hydrogen production for 2030 in Saudi Arabia are mentioned. For the hydrogen price in this study, a prospected value for 2030 is used because the green hydrogen economy is currently emerging and not entirely mature yet (IEA 2023b).

Different studies are prospecting values for the LCOH for 2030. (G. Aziz et al. 2024) prospects an LCOH of \$1.48/kg. An LCOH range from 2.34 to 3.08 \$/kg is prospected according to (Alhadhrami et al. 2024), and an LCOH of 4.28 €/kg with high renewable potential, as well as an LCOH of 4.91 €/kg with low renewable potential (Abdelshafy et al. 2024).

The International Energy Agency (IEA) has reported that the cost of green hydrogen is likely to remain higher than many optimistic projections suggest. This higher-than-anticipated cost is due to several factors, including the substantial capital expenditure required for electrolyzers and the fluctuating cost of renewable energy sources (IEA 2023b).

The same accounts for the hydrogen feedstock price as for the CO₂ feedstock price, considering the importance of acknowledging that predicting the exact future price of feedstocks is inherently uncertain.

Due to the previously mentioned considerations, the assumed hydrogen price in this research will be set at the upper range of the available estimates. This approach excludes lower price projections and aligns with the prospects of (Abdelshafy et al. 2024). Because the renewable energy potential is always fluctuating, a value of 4.5€/kg is used as the base case price for hydrogen as a feedstock in this study as shown in Table 3.3.

3.3. Sensitivity analysis

Sensitivity analysis studies how uncertainty in the output of a model is apportioned to different sources of uncertainty in the input of a model (Saltelli et al. 2004). By changing the assessment parameters, the sensitivity of the results can be investigated easily. In practice, the influence of parameter changes should be investigated for one parameter after the other so that the influence of the specific parameter variation on the results can be seen. Doing this, the sensitivity of the results to changes of different parameters can be investigated (Lauer 2008).

The sensitivity of the LCOM calculation is examined by varying the different parameters that contribute to it. The input parameters for the LCOM calculation can be categorized into two groups: fixed and stable and those likely to change due to external influences.

The fixed and stable parameters include factors that are constant within the project context, such as mass balances, densities, or energy consumption per unit mass. These parameters are unlikely to change significantly over time.

The other category covers parameters influenced by external factors such as time and those determined by choices. These parameters have a significant variability potential. Parameters influenced by time include aspects such as fluctuating market prices for materials and energy. The parameters determined by choices are also very likely to change or be different in real life, such as shipping distance or the size of the vessels and storage tanks.

The first step in conducting a comprehensive sensitivity analysis of the LCOM calculation is to identify and list the parameters that are likely to change over time and that are interesting for the sensitivity

analysis in this research. The categorized list of the parameters that are going to be focused on is provided in Table 3.4.

Dependence	Parameters	Unit
Time	Feedstock price	[€/ton]
Choice	Shipping distance	[km]
	Methanol capacity	[kt/yr]

Table 3.4: Categorized list of the selected input parameters for sensitivity analysis

After identifying the parameters, the values corresponding to the base case scenario are designated as the 'base case value'. For the sensitivity analysis, values lower and higher than this base case value are selected, representing the 'low case' and 'high case' scenarios, respectively. The resulting LCOM's sensitivity to the various input parameters is quantified and subsequently analyzed by the percentage increases or decreases determined for each part of the value chain in the analysis. This approach allows for a systematic examination of the impact of parameter variations on the overall model outcomes. Table 3.5 shows the different cases used for the sensitivity analysis in this research, which are further explained in the following sections.

Case	H ₂ price	CO ₂ price	Distance	MeOH capacity
Low	1.5 €/kg	15 €/ton	0 km	90 kt/yr
Base	4.5 €/kg	85 €/ton	7,500 km	200 kt/yr
High	7.5 €/kg	155 €/ton	14,000 km	310 kt/yr

Table 3.5: Different cases for the parameters used in the sensitivity analysis

When applying the sensitivity analysis, one parameter at a time is changed to test its specific sensitivity.

3.3.1. Feedstock prices

A specific methodology is employed for the sensitivity analysis of the feedstocks. A 'low case' and a 'high case' are defined similarly to the approach used for other parameters subject to sensitivity analysis. Specifically, for the CO₂ and hydrogen feedstock prices, these values represent the lower and upper bounds of the evaluated range. For hydrogen, all intermediate values are assessed with a step size of 0.5 €/kg. For CO₂, the intermediate values are assessed with a step size of 5 €/ton. This approach provides a clear understanding of the sensitivity of these parameters.

Hydrogen

Currently, the high production cost of 'renewable' hydrogen produced by electrolysis is hindering its adoption. Because techno-economic factors affecting the transition to renewable hydrogen are still so uncertain, a realistic price determination is difficult. Moreover, specialists expect that the price of hydrogen will be much higher in practice than we're hypothetically thinking.

The market price of hydrogen is influenced by many factors; some of the most crucial ones are the system cost of an electrolyzer, the capacity factor, and the prices for the feedstocks (Fazeli et al. 2022). Although these factors are out of the scope of this research, they're important to understand the uncertainty of the cost of buying hydrogen at the market.

Because of these high uncertainties, it is very interesting to see the sensitivity analysis results by varying this input parameter. As already stated in Section 3.2.3, the hydrogen price in Saudi Arabia for the base case equals 4.5 €/kg. This base case is defined as the medium value, and a 'low case' and a 'high case' for the price of hydrogen are used in the sensitivity analysis. The values for these prices can be found in Table 3.5.

The hydrogen prices already mentioned in this study range from 1.50 €/kg to 5 €/kg for Saudi Arabia. Multiple studies indicate that prices of 1.50 €/kg in this region are eventually realistic in the future (HC 2023) (Hasan et al. 2021) (IEA 2023b).

By designating 1.5 €/kg as the 'low case' value, this represents a reduction of approximately 2/3 from the base case value. To maintain consistency in the sensitivity analysis, the same percentage range is applied to the upper value. Consequently, the 'high case' value will be 2/3 higher than the base case value, resulting in a price of 7.5 €/kg.

CO₂

New technologies exhibit varying costs due to the ongoing emergence of innovations and the necessity of achieving economies of scale. This is particularly for the technology of capturing CO₂, especially because this is a complex technology with multiple different applications and contexts in which it is used. (IISD 2023) states that this is a reason why the CO₂ capture costs are mostly higher than initially expected.

Furthermore, a report of (Baylin-Stern et al. 2021) highlights that the broad cost variability associated with the CO₂ capture process complicates accurate pricing. Given these uncertainties, it is also interesting to apply sensitivity analysis to this feedstock price. The same approach is used for the hydrogen price. The base scenario utilizes the price of captured CO₂ from Section 3.2.3. This price is defined as the medium value, and this value equals 85 €/ton. The 'low case' and the 'high case' prices used for this sensitivity analysis are shown in Table 3.5.

The lowest CO₂ price mentioned in this study is 15 €/ton, which deviates by approximately 82% from the base case value. This value is designated to be the 'low case' value. To maintain consistency in the sensitivity analysis, the 'high case' value is set at 82% above the base case value, resulting in a CO₂ feedstock price of 155 €/ton.

This approach allows for a comprehensive understanding of how the variations in hydrogen and CO₂ capture costs can impact the overall economic viability of the value chain considered in this research.

3.3.2. Shipping distance

In the base case of this study, it is assumed that hydrogen is sourced from Saudi Arabia. In both scenarios, shipping is considered for the distance between the port of Jeddah, Saudi Arabia, and the Port of Rotterdam, which equals 7,500 km when cruising via the Suez Canal with a direct connection as shown in Figure 3.1.

Two additional distances are examined for the sensitivity analysis of the shipping distance. The 'low case' represents a scenario with a shorter shipping distance than the base case, while the 'high case' involves shipping the products over a longer distance. In the 'low case' scenario, this study examines the potential price of hydrogen sourced directly at the Port of Rotterdam, which implies that shipment is eliminated. This variation also aims to determine the potential price at which the LCOM remains consistent with the base scenario.

In the low case, only a single configuration is considered, where methanol is produced domestically in the Netherlands using locally sourced hydrogen and CO₂. The value chain components for methanol production in this case include solely the methanol synthesis process and its feedstocks, and the methanol storage facility. Recent analysis from (Burchardt et al. 2023) indicates the anticipated green hydrogen production costs in Europe. Initially, it was expected to be below 3€/kg, but this has proven unrealistic due to elevated energy market prices and structural challenges in renewable project supply chains. Consequently, the current hydrogen project suggests that production will range from 5€/kg to 8€/kg by 2030 in Europe. Due to the same considerations as mentioned in Section 3.2.3, the assumed hydrogen price in this research will be set at the upper range of the available estimates. A hydrogen price of 8€/kg is used for domestic methanol production with locally sourced feedstocks in this low case.

An alternative country is considered in the 'high case' scenario of the sensitivity analysis for shipping distance. This country is approximately twice the distance away from the Port of Rotterdam compared to the Port of Jeddah, with the requisite that it shares similar renewable energy conditions. Because this country shared similar conditions regarding renewable energy potential, the energy consumption tariffs for this alternative country are assumed to be identical to those of Saudi Arabia.

The country chosen in the 'high case' scenario is Chile, with its specific port of Antofagasta. This port is 14,000 km away from the Port of Rotterdam and is situated in the northern part of Chile. According

to the Global Solar Atlas (WBG 2024), this area of Chile has a solar energy potential equal to or even higher than that of Saudi Arabia. This route is shown in Figure 3.3.



Figure 3.3: Shipping route between the Port of Antofagasta (CL) and the Port of Rotterdam (NL) considered in the sensitivity analysis in this study

3.3.3. Methanol capacity

In this study's base case scenario, a methanol production rate of 200 kt per year is assumed. The methanol unit's production capacity, situated at the end of the value chain, significantly influences every component within the value chain due to the bottom-up approach employed in this analysis. Because this parameter plays a prominent role in this study, it is chosen as one of the sensitivity parameters. The lower and upper values for the methanol capacity have to be determined.

GIDARA Energy and the Port of Rotterdam announced a renewable methanol facility located in the port area. It is expected that this plant will have a production capacity of 90 kt of renewable methanol per year. The facility started detail engineering and construction in the first half of 2023 and planned to start production of renewable methanol in 2025 (GIDARA Energy 2024).

Given that this is an actual project ready to enter the construction phase next year, it is valuable to evaluate the outcomes by utilizing this capacity as the methanol production rate. Consequently, a capacity of 90 kt/yr will be designated as the 'low case' scenario for methanol production capacity.

The lower limit exhibits a 55% deviation from the base case value. To ensure consistency in the sensitivity analysis, the upper limit also incorporates a 55% deviation from the base case. This adjustment results in a 'high case' value of 310 kt/yr.

4

Scenario analysis and comparison

This Chapter presents the detailed results of the scenario analysis within the base case of this study in Section 4.1. The results of the scenarios are subsequently compared to each other by a comprehensive comparison in Section 4.2. Following the scenario comparison, the results of the sensitivity analysis are discussed and evaluated in Section 4.3.

4.1. Scenario analysis results

In the subsequent Sections, the different Scenarios of the E-methanol value chain are analyzed. Specific methodologies are applied as necessary to ensure a comprehensive evaluation. This detailed analysis encompasses the technological, economic, and operational aspects of each component, providing a robust framework for the overall assessment of the value chain.

First, Section 4.1.1 provides an analysis of Scenario 1. This is followed by an analysis of Scenario 2a in Section 4.1.2, Scenario 2b in Section 4.1.3, and finally, Scenario 2c in Section 4.1.4. After analyzing the different Scenarios, the results of the sensitivity analysis are discussed in Section 4.3.

4.1.1. Scenario 1: CO₂ export and E-MeOH import

This section presents the results obtained from the analysis of the various infrastructure components in Scenario 1 of the E-methanol value chain considered in this study. Each component allows for specific design choices, which are explained in the subsequent subsections. Figure 4.1 illustrates the components of the E-methanol value chain considered in this Scenario, with the export of captured CO₂ from the Netherlands to Saudi Arabia and the import of E-methanol.

In the Netherlands, captured CO₂ is liquefied upon arrival at the liquefaction plant and stored in temporary storage tanks. The liquefied CO₂ is then loaded onto a CO₂-carrying ship and transported to Saudi Arabia, where it is temporarily stored in storage tanks. In Saudi Arabia, the CO₂ is pumped and heated to conditions suitable for subsequent methanol synthesis. Hydrogen, produced locally, and the reconditioned CO₂ are fed into the methanol synthesis reactor. The synthesized methanol is stored temporarily near the production site before being shipped back to the Netherlands. Once in the Netherlands, the methanol is again temporarily stored and subsequently distributed for further use across the country and its hinterlands.

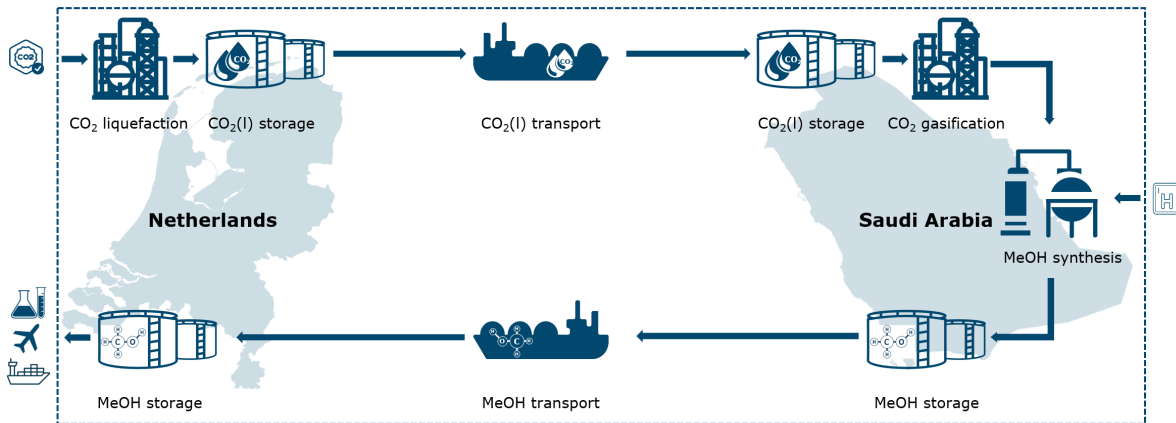


Figure 4.1: Components of Scenario 1 and its boundary conditions considered in this research

Summary of Scenario 1

For the methanol synthesis at an annual production rate of 200 kt, this scenario necessitates the consumption of 40 kt of hydrogen and 305 kt of CO₂ per year. The value chain in this scenario requires a total of 101 GWh of electrical energy and 1.1 TWh of thermal energy annually. The total capital expenditure (CAPEX) for the value chain is 362 million €, while the total operational expenditure (OPEX) amounts to 31 million € per year. The annual costs for the feedstocks in this scenario are 180 M€/yr for hydrogen and 26 M€/yr for CO₂. Figure 4.2b represents the proportion of each category of expense related to the total cost.

The techno-economic analysis of this Scenario results in a total Levelized Cost of Methanol (LCOM). The additions of the LCOM for each component provide a comprehensive overview of the total cost across the entire value chain. This cumulative LCOM is illustrated using a waterfall diagram, shown in Figure 4.2a. The waterfall diagram breaks down and visualizes the contributions of each individual cost component. This offers a clear view of how each component adds to the overall cost within the value chain, and understanding these cost distributions is crucial for the identification of the key cost drivers and areas for potential optimization.

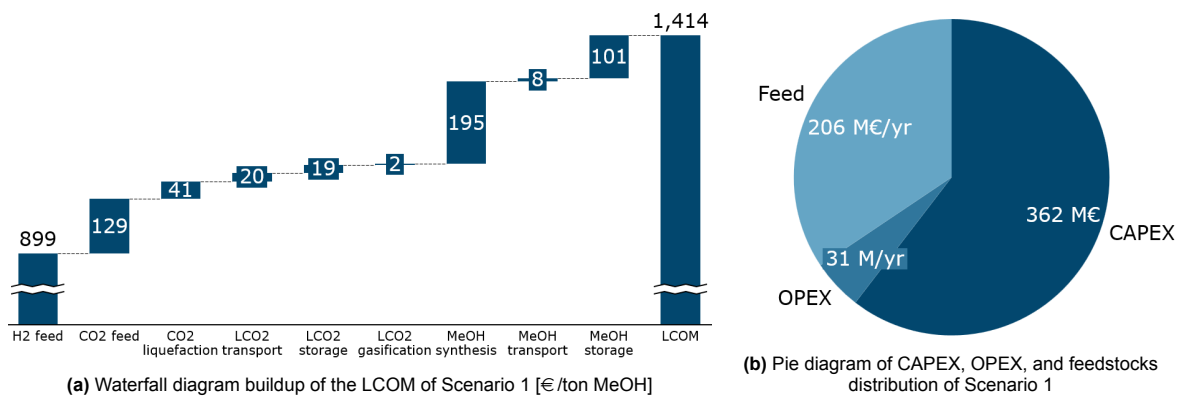


Figure 4.2

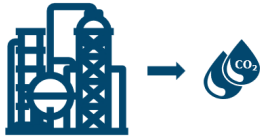
The total LCOM of Scenario 1 amounts to 1,4 € per kg of methanol produced. As shown in Figure 4.2a, the hydrogen feedstock emerges as the most significant contributor to the overall levelized cost. This highlights the substantial impact of hydrogen sourcing on the economic viability of the methanol production process.

When analyzing the costs associated with infrastructure components and conversion facilities, it becomes clear that the methanol production unit of these components has the highest expenditure. This

indicates that the methanol synthesis itself is a major cost driver within the value chain. The following subsections provide an in-depth examination of the components within this value chain, presenting both the technical and economic analyses for each component.

The elaboration of the calculated results for the different components considered in this value chain is explained in the following subsections.

CO₂ compression and liquefaction in the Netherlands



Summary of results

Parameter	Value	Unit
CO ₂ (g) feed	305	kt/yr
CO ₂ (l) product	297	kt/yr
Electrical energy	30	GWh
CAPEX	36	M€
OPEX	3.6	M€/yr
LCOM	41	€/ton

When importing CO₂ in its liquid state, the captured gas undergoes initial compression and subsequent liquefaction to enhance economic viability. Among the segments comprising the CO₂ transport chain, the liquefaction plant is the most energy-intensive component (Zahid et al. 2014). In this study, the CO₂ compression and liquefaction unit is situated in the Netherlands

Several liquefaction processes are proposed in the literature. The general principle of liquefaction is a combination of process stages of cooling and compression of the CO₂. In this study, post-combustion captured CO₂ is liquefied at semi-pressurized pressure. The density of liquid CO₂ decreases, and the cost of storage tanks increases with increasing pressure. Therefore, it is most cost-effective to ship CO₂ at low pressure and temperature. Most studies assume a transport condition close to the triple point, where CO₂ coexists in the gaseous, liquid, and solid form, for CO₂ shipping (Durusut et al. 2018). Therefore, CO₂ is liquefied to -52°C and 6.5 bar in this study.

The literature of (Zahid et al. 2014) uses a modified design of the design proposed by (Aspelund et al. 2005) and (Lee et al. 2012) to improve the liquefaction energy requirement. This modified design is used in this study.

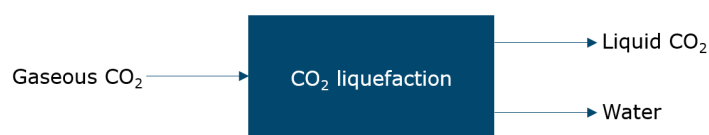


Figure 4.3: CO₂ liquefaction unit flowchart

Stream	Molar composition	Flowrate	Conditions
Gaseous CO ₂	94.39% CO ₂ , 5.61% H ₂ O	304.5kt/yr	1.01 bar, 35°C
Liquid CO ₂	99.88% CO ₂ , 0.12% H ₂ O	297.3 kt/yr	6.5 bar, -52°C
Water	100% H ₂ O	7.2 kt/yr	

Table 4.1: Flow streams for the CO₂ liquefaction unit

The composition of the initial gaseous CO₂ is shown in table 4.1. It mainly comprises CO₂, water, and possibly trace amounts of amine solvent. However, the capture process can treat these gases until only a negligible amount remains.

This gaseous CO₂ feed stream is compressed using four stages of compressors and uses inter-coolers with seawater to cool down the compressed streams. This seawater is assumed to be 10 °C. During the CO₂ liquefaction process, the water content in the liquid stream should be removed until it is less than 500 ppm to avoid the formation of hydrates, freezing of water, and corrosion. Flash drums are placed strategically in the liquefaction unit to remove any excess water content in the CO₂ stream. The main purpose of a flash drum in this configuration is to separate liquid from vapors to ensure compressor safety.

As the gas is compressed and cooled, most of the remaining water is condensed and removed in the flash drums before the compression. The recovered water is subsequently sent to a flash drum before the first compression stage to recover the CO₂ dissolved in the water at high pressure. Finally, the liquid CO₂ is delivered at -52°C and 6.5 bar (Zahid et al. 2014).

The modified design from (Zahid et al. 2014) has a liquefaction energy requirement of 97.3 kWh per tonne of CO₂ feed to the liquefaction unit. This liquefaction energy only consists of electrical energy. With a feed stream of 305 kt/yr, the electrical energy consumption of this liquefaction unit is 30 GWh.

The CAPEX from the liquefaction unit in the literature of (Lee et al. 2012) is used as a reference value for the cost calculation. This unit delivers 2.8 Mt/yr of liquid CO₂ with a CAPEX of 105.5 M€₂₀₁₂. This value is inflation-adjusted to 2024 according to CEPCI and scaled with the six-tenths rule (3.1) to deliver 297 kt of liquid CO₂ per annum. Then, the CAPEX for the CO₂ liquefaction unit equals 35.7 M€₂₀₂₄.

The fixed OPEX equals 2.5% of the CAPEX, which results in 0.86 M€₂₀₂₄/yr. The variable OPEX is calculated according to the utilities, which are dominated by electricity costs for refrigeration and compression. This value results in 2.8 M€₂₀₂₄/yr. Therefore, the total OPEX results in 3.64 M€₂₀₂₄/yr.

CO₂ liquefaction: Levelized Cost of Methanol

In this analysis, a CAPEX of 36 M€ and an OPEX of 3.6 M€ per year are considered for the liquefaction unit. Using these values, the LCOM for the CO₂ liquefaction unit is calculated to be 41 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

CO₂(l) transport from the Netherlands to Saudi Arabia



Summary of results

Parameter	Value	Unit
Ship capacity	30,000	m ³
Trips per year	9	trips
OPEX	4.0	M€/yr
LCOM	20	€/ton

After the liquefaction, the CO₂ is ready for shipment from the Netherlands to Saudi Arabia. Economic large-scale CO₂ transport is ideally done in semi-pressurized vessels at pressures near the triple point. Under 6.5 bar and -52°C conditions, the liquefied CO₂ is loaded onto the ship. An additional bonus by transporting CO₂ under these conditions is that it has the highest density possible in the liquid state (Aspelund et al. 2005). For the liquid CO₂ transportation configuration in this study, the methodology of (Spatolisano, Restelli, et al. 2024) is partly employed and adjusted to CO₂ specifications.

First, the consumed time for one round trip is calculated. The distance between the two terminals is approximately 7,500 km. When cruising with the assumed speed of 26 km/h, the cruising time will be ≈ 13 days. The total time of one round trip is calculated with equation 4.1. This encompasses the entirety of the period from the vessel's departure from one terminal to its subsequent return to the same terminal.

$$t_{roundtrip} = 2 \cdot t_{cruising} + t_{loading+unloading} + t_{marging} \quad (4.1)$$

As a safety margin, 2 days are accounted for managing possible delays. The time for loading and unloading the methanol is 1 day. This results in a total time of 29 days until the vessel returns to the same terminal.

Most publications focusing on low-pressure transport conditions propose using either existing designs of semi-refrigerated LPG ships or modifications of those. The literature of (Baroudi et al. 2021) states that large-scale CO₂ shipping can significantly benefit from knowledge developed by the more established LNG and LPG industries. Despite the difference in pressure and temperature requirements, liquid CO₂ near the triple point has a comparable liquid/gas density ratio to LNG, making comparisons more appropriate. The sizes for suitable CO₂ ships are available in a wide range up to 100,000 m³ based on the feasibility and existing technology used in the LNG and LPG industry. (Durusut et al. 2018) stated that carrier vessels for carbon dioxide transport with a size of 30,000 m³ are feasible and do not pose significant new technical challenges. Therefore, a CO₂ vessel size of 30,000 m³ is used in this study.

With a density of 1160 kg/m³ for liquid CO₂ at the specific transport conditions, the weight loaded onto a vessel with a capacity of 22,000 m³ is 35 kt per trip. The annual amount of CO₂ for the methanol production is 297 kt per year. Therefore, this CO₂ ship must make 9 yearly trips to transport the annual quantity.

Because the ship is not cruising the entire time of the year, chartering a ship is preferred instead of buying and taking full ownership of it. The configuration of ship chartering of (Meca et al. 2022) is used.

(Lim et al. 2022) considers a LNG ship with a capacity of 160,000 m³, with a charter rate of 74,000 \$₂₀₂₁/day ($C_{charter}$). A total of 15,000 \$₂₀₂₁/day of non-proportional voyage costs are assumed per roundtrip per land terminal ($C_{np,voyage}$) (Meca et al. 2022). As per loading and offloading, the facilities are included in the analysis of this logistic chain, therefore no additional tolls or fees are foreseen.

The values are scaled to the desired capacity of the ship, inflation adjusted to 2024 using CEPCI and converted to euros. This results in $C_{charter} = 14,742 \text{ €/day}$ and $C_{np,voyage} = 15,937 \text{ €/roundtrip}$.

The cost associated with the chartering of the transport facility for methanol is calculated with equation 4.2.

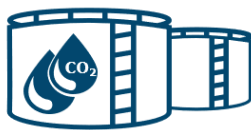
$$C_{shipping} = N_{roundtrips} \cdot (t_{roundtrip} \cdot C_{charter} + C_{voyage}) \quad (4.2)$$

Thus, the annual shipping cost of CO₂ from the Netherlands to Saudi Arabia in this study is OPEX based and equals 4.0 M€₂₀₂₄/year.

CO₂ transport: Levelized Cost of Methanol

In this analysis, an OPEX of 4.0 M€ per year is considered for the transport facility of liquid CO₂. Using these values, the LCOM for the CO₂ liquid transport component is calculated to be 20 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

CO₂(l) storage



Summary of results

Parameter	Value	Unit
Total capacity	66,000	m ³
CAPEX	17	M€
OPEX	1.7	M€/yr
LCOM	19	€/ton

While the flow of CO₂ from a source, such as a power plant or industrial emitter, and the subsequent liquefaction is continuous, the shipping occurs in discrete runs and is a batch process. Therefore, an intermediate buffer storage is needed to store the CO₂ when there is no ship in the port. There are two advantages to intermediate storage tanks. First, a steady CO₂ flow can be provided to the storage site, which is important for safe transmission and uninterrupted operation of the storage site. Secondly, in the case of regular or unforeseen maintenance at the storage site, an intermediate tank will provide a buffer between CO₂ capture and storage process.

CO₂ storage under low temperatures requires the use of specialized low-temperature materials from steel. Storage tank material and equipment are required to withstand a range of CO₂ pressures and temperatures on either side of the intended operational values, which is a huge advantage because the conditions of the stored or transported CO₂ can vary a bit during operation (Durusut et al. 2018)

If a ship is unexpectedly delayed, this storage unit should be sufficient to cover these delays. Different safety margins are discussed in the literature to allow for operational flexibility, which sizes up to 150% of the ship capacity (Seo et al. 2016). In this study, the capacity of the storage tank considers the volume of the vessel increased by 10%, as can be calculated with equation 4.3.

$$V_{tank} = (1 + 0.1) \cdot V_{ship} \quad (4.3)$$

When using the ship capacity of (Durusut et al. 2018) for liquid CO₂ shipping, which equals 30,000 m³, the total capacity of tanks per terminal will be equal to $V_{tank} = (1 + 0.1) \cdot 30,000 = 33,000$ m³. Because storage at both terminals is required, the total storage capacity needed for liquid CO₂ is 66,000 m³.

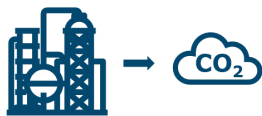
Because liquid CO₂ near the triple point has a comparable liquid/gas density ratio to LNG, as already stated in the previous section, the storage of liquid CO₂ is compatible with existing storage and infrastructure for fossil fuels. The same accounts for methanol and LOHC storage as shown in Section 4.1.1 and 4.1.4, respectively. Therefore, the same cost per cubic meter is used as in these storage configurations.

According to (Niermann et al. 2019), the investment costs of the conventional fossil fuel storage tanks amount to 192 €₂₀₁₉/m³. When adjusting this value to 2024 with CEPCI and multiplying this with the total volume multiplied by two, because of the storage units at both terminals, the CAPEX for the CO₂ storage facility in this study equals 16.8 M€₂₀₂₄. With this CAPEX, the total OPEX of the CO₂ storage facility equals 1.7 M€₂₀₂₄/yr.

CO₂ storage: Levelized Cost of Methanol

In this analysis, a CAPEX of 17 M€ and an OPEX of 1.7 M€ per year are considered for the storage units. Using these values, the LCOM for the CO₂ storage units is calculated to be 19 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

CO₂(l) reconditioning in Saudi Arabia



Summary of results

Parameter	Value	Unit
CO ₂ (l) feed	297	kt/yr
CO ₂ (g) product	297	kt/yr
Electrical energy	1.8	GWh
CAPEX	2	M€
OPEX	0.2	M€/yr
LCOM	2	€/ton

After receiving CO₂ at a facility, the CO₂ must be reconditioned to meet the requirements for further uses. To bring the CO₂ to the required conditions, it is pumped to the appropriate pressure and heated to the appropriate temperature using a heat exchanger (Roussanaly et al. 2021). Compressing liquid CO₂ using pumps requires much less energy than compressing gaseous CO₂ using compressors due to the significantly smaller specific volume of liquid CO₂ (Durusut et al. 2018).

The energy requirements for pumping and heating CO₂ vary depending on the injection and transport conditions. It is usually assumed that seawater is used in the heat exchanger to heat the CO₂. In the case of onshore unloading, gasification happens after the ship is unloaded to temporary storage. In addition to the pressure requirement from the storage site, the CO₂ must be pumped to sufficient pressure to overcome the pipeline pressure.

According to the literature of (Bjerketvedt et al. 2020), the energy consumption for the reconditioning process at low pressure is 6.14 kWh/ton_{CO₂}. This results in an energy consumption of 1.82 GWh electrical energy in this study when processing an annual flowrate of 297 kt of CO₂.

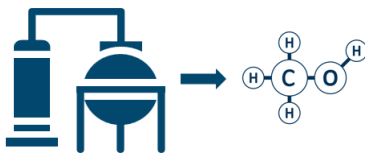
For the cost calculation, the CAPEX of the CO₂ reconditioning process at low pressure from the literature of (Bjerketvedt et al. 2020) is used as a reference value. This reference unit reconditioned 5 Mt CO₂/yr and has a CAPEX of 8 M€₂₀₂₀. This value is adjusted to 2024 using CEPCI and scaled with the six-tenths rule (3.1) to the desired capacity, which results in a CAPEX of 1.98 M€₂₀₂₄.

The fixed OPEX equals 2.4% of the CAPEX, resulting in 0.05 M€₂₀₂₄/yr. The variable OPEX is calculated according to the energy utilities, which are the only electricity costs. This value results in 0.14 M€₂₀₂₄/yr. Therefore, the total OPEX results in 0.19 M€₂₀₂₄/yr.

CO₂ reconditioning: Levelized Cost of Methanol

In this analysis, a CAPEX of 2 M€ and an OPEX of 0.2 M€ per year are considered for the CO₂ gasification unit. Using these values, the LCOM for the CO₂ gasification unit is calculated to be 2.2 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

E-MeOH production in Saudi Arabia



Summary of results

Parameter	Value	Unit
H ₂ feed	40	kt/yr
CO ₂ feed	297	kt/yr
CH ₃ OH product	200	kt/yr
Electrical energy	70	GWh
Thermal energy	1.1	TWh
CAPEX	219	M€
OPEX	11	M€/yr
LCOM	195	€/ton

In this study, the assumed capacity of the methanol synthesis plant is 200 kt/year. In this scenario, the methanol synthesis plant is located in Saudi Arabia.

The methanol production facility employed to scale is based on the conceptual design proposed by (Cameli et al. 2024). His 50 kt/year E-MeOH production plant uses DAC-CO₂ and electrolytic H₂, these processes are out of the scope of this research, and therefore only the methanol synthesis unit is considered together. The CO₂ and H₂ streams are separately compressed to 78 bar and mixed with a recycle stream before entering the reactor at 210°C. The methanol synthesized in this process is delivered at atmospheric pressure and 64.1°C and has a purity of 99.85%. After leaving the reactor, the methanol is fed to a distillation unit and finally delivered at 30 degrees and atmospheric pressure as liquid methanol.

For the methanol synthesis unit, the flow streams considered are visually shown in figure 4.4, and its values are converted to the assumed production of 200 kt methanol per year according to the data from (Cameli et al. 2024) and shown in table 4.2:

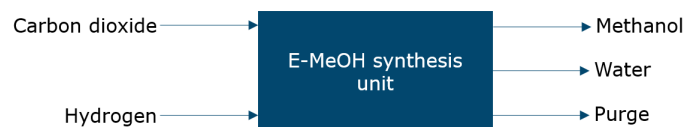


Figure 4.4: E-MeOH synthesis unit flowchart

Stream	Molar composition	Flowrate	Conditions
Carbon dioxide	100% CO ₂	297.31 kt/yr	1 bar, 19°C
Hydrogen	100% H ₂	39.94 kt/yr	31 bar, 80°C
Methanol	99.79% CH ₃ OH, 0.18% H ₂ O, 0.04% CO ₂	200 kt/yr	1 bar, 64.1°C
Water	99.98% H ₂ O, 0.02% CH ₃ OH	114.47 kt/yr	1.2 bar, 103.8°C
Purge	Mix	23.77 kt/yr	bar, °C

Table 4.2: Flow streams for the E-methanol synthesis unit

This plant has an energy consumption that consists of 349 kWh/t MeOH for electricity and 1.99 MWh/t_{MeOH} and 3.41 MWh/t_{MeOH} for heating and cooling duties, respectively. With the annual production of 200 kt methanol, the electricity consumption of the methanol synthesis unit results in 70 GWh, the heat duties result in 399 GWh, and the cooling duties result in 683 GWh.

For the cost calculation of the methanol synthesis unit, the CAPEX of the 50kt/yr unit is used as a reference value and equals 76.8 M\$₂₀₁₉. The assumed production capacity of the methanol synthesis plant is 200 kt/yr. The value for the CAPEX is adjusted to 2024 using CEPCI, converted to euros, and scaled to the assumed capacity with the six-tenth rule. This results in a CAPEX of 219.52 M€₂₀₂₄.

The fixed OPEX is 2.4% of the CAPEX, which equals 5.25 M€₂₀₂₄/yr, and the variable OPEX is calculated with the consumed utilities and the assumed prices; this results in 5.77 M€₂₀₂₄/yr. The total OPEX of the methanol synthesis unit is 11.01 M€₂₀₂₄/yr.

E-MeOH production: Levelized Cost of Methanol

In this analysis, a CAPEX of 219 M€ and an OPEX of 11 M€ per year are considered for the methanol synthesis unit. Using these values, the LCOM for the methanol synthesis unit is calculated to be 195 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

E-MeOH transport from Saudi Arabia to the Netherlands



Summary of results

Parameter	Value	Unit
Ship capacity	160,000	m ³
Trips per year	2	trips
OPEX	1.6	M€/yr
LCOM	8	€/ton

After the 200 kt E-methanol production in Saudi Arabia, the methanol must be shipped back to the Netherlands. Methanol transportation as a bulk liquid is relatively easy to handle under ambient pressure and temperature compared to alternatives, and current crude oil cargo vessels could be used to

transport methanol with only minor modifications (Schorn et al. 2021). For the methanol transportation configuration in this study, the methodology of (Spatolisano, Restelli, et al. 2024) is partly employed and adjusted to methanol specifications. The roundtrip time is calculated using the same method as in Section 4.1.1 and equals 29 days when cruising with a speed of 26 km/h.

The ship capacity for methanol transportation from the literature of (Al-Breiki et al. 2020) is used in this study and equals 160,000 m³. With a density of methanol of 0.8 t/m³ obtained from the literature of (Ong et al. 2024), the weight loaded onto this ship is 128 kt per trip. The annual methanol production rate in this study is 200 kt per year. Therefore, this methanol ship must only make two yearly trips to transport the annual quantity.

Because the ship only makes two trips a year, chartering a ship is preferred instead of buying and taking full ownership of it. (Meca et al. 2022) considers a ship with a capacity of 120,000 m³ that currently transports methanol, with a charter rate of 19,000 USD₂₀₂₂/day ($C_{charter}$). A total of 15,000 USD₂₀₂₂ of non-proportional voyage costs are assumed per roundtrip per land terminal ($C_{np,voyage}$). As per loading and offloading, the facilities are included in the analysis of this logistic chain, therefore no additional tolls or fees are foreseen.

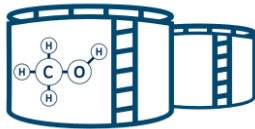
The values are scaled to the desired capacity of the ship, inflation adjusted to 2024 using CEPCI, and converted to euros. This results in $C_{charter} = 26,916 \text{ €/day}$ and $C_{np,voyage} = 21,250 \text{ €/roundtrip}$.

The cost associated with the chartering of the transport facility for methanol is calculated with equation 4.2. Thus, the annual shipping cost of methanol from Saudi Arabia to the Netherlands in this study is OPEX based and equals 1.6 M€₂₀₂₄/year.

E-MeOH transport: Levelized Cost of Methanol

In this analysis, an OPEX of 1.6 M€ per year is considered for the transport facility of methanol. Using these values, the LCOM for the methanol transport component is calculated to be 8 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

E-MeOH storage



Summary of results

Parameter	Value	Unit
Total capacity	352,000	m ³
CAPEX	89	M€
OPEX	8.9	M€/yr
LCOM	101	€/ton

Methanol can be relatively easily stored at atmospheric pressure and ambient temperature. The way of storing methanol is approximately the same as that of other liquid fuels, but it requires some specific safety considerations. Moreover, its storage is relatively affordable with negligible losses.

In this study, only the CAPEX related to purchasing the storage tank is considered for the storage of methanol. The OPEX is related to the maintenance and insurance and accounts for 10% of the CAPEX. The losses during storage are assumed to be negligible.

At each operating terminal, a storage facility must be established. The capacity of the storage tank is calculated with equation 4.3 and is computed considering the storage of the volume transported by the vessel increased by 10% as a safety margin for possible delays (Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024).

When using the ship capacity of (Al-Breiki et al. 2020) for liquid methanol bulk transport, which equals 160,000 m³, the total capacity of the tanks per terminal will be equal to $V_{tank} = (1 + 0.1) \cdot 160,000 = 176,000 \text{ m}^3$. Because storage at both terminals is required, the total storage capacity needed for liquid CO₂ is 352,000 m³.

Just like LOHC storage, the storage of methanol is also compatible with existing storage and infrastructure for fossil fuels. Therefore, the same cost per cubic meter is used as in the LOHC storage configuration in Section 4.1.4.

According to (Niermann et al. 2019), the investment costs of the conventional fossil fuel storage tanks, amount to $192 \text{ €}_{2019}/\text{m}^3$.

When adjusting this value to 2024 with CEPCI and multiplying this with the total volume multiplied by two because of the storage at both terminals, the CAPEX for the LOHC storage facility in this study equals 89.4 M€_{2024} . With this CAPEX, the total OPEX of the LOHC storage facility equals $8.9 \text{ M€}_{2024}/\text{yr}$.

E-MeOH storage: Levelized Cost of Methanol

In this analysis, a CAPEX of 89 M€ and an OPEX of 9 M€ per year are considered for the storage units. Using these values, the LCOM for the methanol storage units is calculated to be 101 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

4.1.2. Scenario 2a: H_2 import as LH_2

This section presents the results obtained from the analysis of the various infrastructure components in Scenario 2a of the E-methanol value chain considered in this study. Each component allows for specific design choices, which are explained in the subsequent subsections. Figure 4.5 illustrates the components of the E-methanol value chain considered in this Scenario, with the import of hydrogen in liquid form from Saudi Arabia to the Netherlands.

In Saudi Arabia, produced hydrogen is fed to a liquefaction plant, liquefied, and stored in temporary storage tanks. The liquid hydrogen is then loaded onto an LH_2 -carrying ship and transported to the Netherlands, where it is again temporarily stored in storage tanks. In the Netherlands, the liquid hydrogen is gasified to have suitable conditions for the subsequent methanol synthesis. The locally captured CO_2 and the reconditioned hydrogen are fed into the methanol synthesis reactor. The synthesized methanol is temporarily stored near the production site before being distributed for further use across the country and its hinterlands.

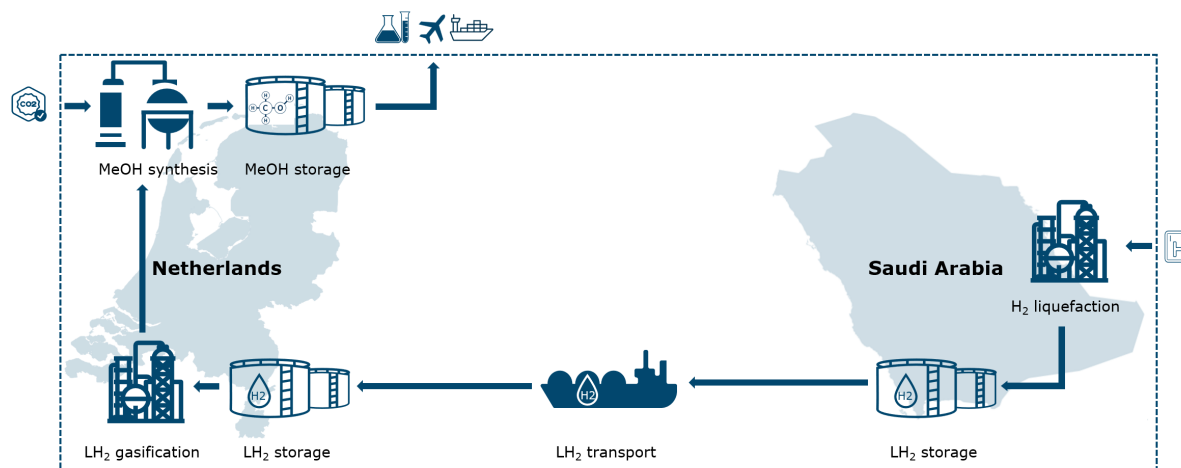


Figure 4.5: Components of Scenario 2a and its boundary conditions considered in this research

Summary of Scenario 2a

For the methanol synthesis at an annual production rate of 200 kt, this scenario necessitates the consumption of 41 kt of hydrogen and 297 kt of CO_2 per year. The value chain in this scenario requires a total of 412 GWh of electrical energy and 1.5 TWh of thermal energy annually. The total capital expenditure (CAPEX) for the value chain is 772 million €, while the total operational expenditure (OPEX) amounts to 91 million € per year. The annual costs for the feedstocks in this scenario are $185 \text{ M€}/\text{yr}$

for hydrogen and 25 M€/yr for CO₂. Figure 4.6b represents the proportion of each category of expense related to the total cost.

The techno-economic analysis of this Scenario results in a total Levelized Cost of Methanol (LCOM). The additions of the LCOM for each component provide a comprehensive overview of the total cost across the entire value chain. This cumulative LCOM is illustrated using a waterfall diagram, shown in Figure 4.6a. The waterfall diagram breaks down and visualizes the contributions of each individual cost component. This offers a clear view of how each component adds to the overall cost within the value chain, and understanding these cost distributions is crucial for the identification of the key cost drivers and areas for potential optimization.

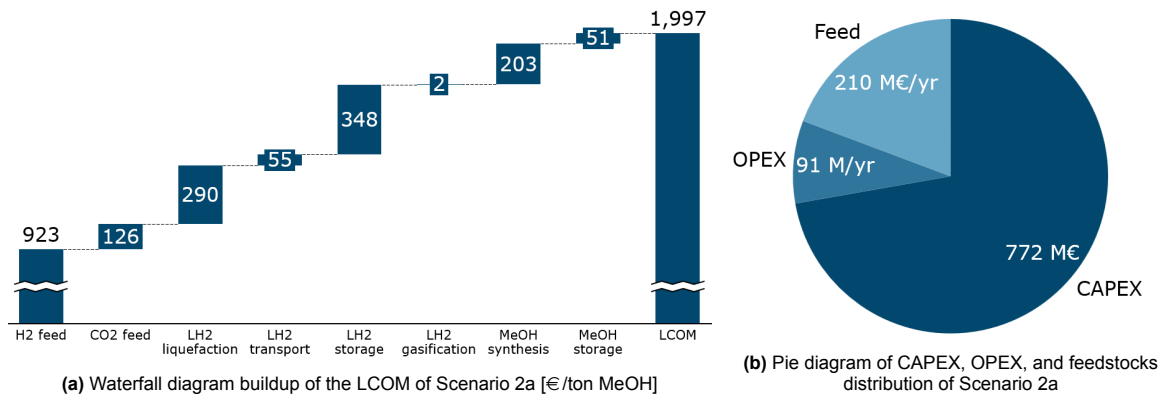


Figure 4.6

The total LCOM of Scenario 1 amounts to 2.0 € per kg of methanol produced. As shown in Figure 4.6a, the hydrogen feedstock emerges as the most significant contributor to the overall levelized cost. This highlights the substantial impact of hydrogen sourcing on the economic viability of the methanol production process.

When analyzing the costs associated with infrastructure components and conversion facilities, it becomes clear that the liquid hydrogen storage facility has the highest expenditure. The hydrogen liquefaction unit also has a relatively high contribution to the LCOM compared to the other components in this Scenario. This indicates that the conversion and the handling of liquid hydrogen are major cost drivers when considering this option for hydrogen import. The following subsections provide an in-depth examination of the components within this value chain, presenting both the technical and economic analyses for each component.

The elaboration of the calculated results for the different components considered in this value chain is explained in the following subsections.

Hydrogen liquefaction in Saudi Arabia



Summary of results

Parameter	Value	Unit
H ₂ feed	41	kt/yr
LH ₂ product	41	kt/yr
Electrical energy	341	GWh
Thermal energy	375	GWh
CAPEX	202	M€
OPEX	32	M€/yr
LCOM	290	€/ton

When importing hydrogen in its liquid form, first the hydrogen needs to be liquefied. The hydrogen liquefaction process consists of the cooling of hydrogen to the condition of saturated liquid at storage tank pressure. For this process, a configuration from the literature of (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024) is used as a reference configuration. In this study, this liquefaction plant is considered situated within Saudi Arabia and it is assumed that this plant operates continuously throughout the year.

They compare three different process configurations: a liquid nitrogen pre-cooled Claude cycle, a mixed-refrigerant (MR) pre-cooled Claude cycle, and an MR cascade process. Based on their performances, the MR pre-cooled Claude cycle is the best choice for the liquefaction process in this literature. Therefore, this study uses this process as a reference configuration. This reference liquefaction unit processes 15.8 kt of hydrogen annually.

In this process, the gaseous hydrogen is fed at a temperature of 25°C and a pressure of 20 bar to the liquefaction plant. After pre-cooling the gaseous hydrogen, the hydrogen passes several heat exchangers and compressors inside this plant. Finally, the hydrogen is delivered in liquid form at a temperature of -252°C and a pressure of 1.3 bar. These flow streams are visualized in figure 4.7, and their corresponding values and conditions are shown in table 4.3.

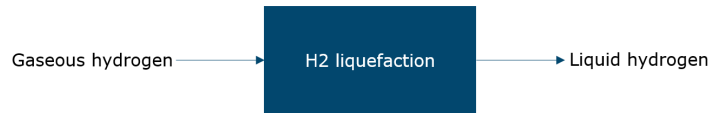


Figure 4.7: H₂ liquefaction unit flowchart

Stream	Flowrate	Conditions
Gaseous hydrogen	41 kt/yr	20 bar, 25°C
Liquid hydrogen	41 kt/yr	1.3 bar, -252°C

Table 4.3: Flow streams for the H₂ liquefaction unit

The energy consumption for this hydrogen liquefaction process consists of 5.61 MWh/t_{H₂} of cooling energy provided by cooling water, 3.54 MWh/t_{H₂} of refrigerant energy provided by refrigerant water, and 8.32 MWh/t_{H₂} of electric energy. In this study, an annual amount of 41 kt/yr of hydrogen is used for the liquefaction process. This gives a total annual energy consumption of 228 GWh for cooling energy, 144 GWh for refrigerant energy, and 338 GWh for electric energy.

For the cost calculation, the CAPEX from the liquefaction unit in the literature of (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024) is used as a reference value. This unit uses 15.8 kt hydrogen per year and has a CAPEX of 116 M€₂₀₂₂. This value is inflation adjusted to 2024 using CEPCI and scaled to the desired capacity with the six-tenths rule as depicted in equation (3.1). This results in a CAPEX of 202 M€₂₀₂₄.

The fixed OPEX equals 2.4% of the CAPEX, which results in 4.8 M€₂₀₂₄/yr. The variable OPEX is calculated according to the utilities: the energy consumption. This variable OPEX equals 27.4 M€₂₀₂₄/yr, which results in a total OPEX of 32 M€₂₀₂₄/yr.

H₂ liquefaction: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the hydrogen liquefaction unit, the Levelized Cost of Methanol (LCOM) for this unit can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 202 M€ and an OPEX of 32 M€ per year are considered for the liquefaction unit. Using these values, the LCOM for the hydrogen liquefaction unit is calculated to be 290 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational

costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

Liquid hydrogen transport from SA to NL



Summary of results

Parameter	Value	Unit
Ship capacity	37,500	m ³
Trips per year	16	trips
OPEX	11	M€ /yr
LCOM	55	€ /ton

For the transport section of liquid hydrogen from Saudi Arabia to the Netherlands, the methodology outlined by (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024) for shipping configuration is employed. This methodology involves an LNG shipping vessel. Additionally, the vessel's capacity is based on the conceptual design provided by (LH2 Europe 2024), specifying a total volume of 37,500 m³. The operational assumption for this vessel includes a cruising speed of approximately 26 km/h. The roundtrip time is calculated using the same method as in Section 4.1.1, and equals 29 days.

With a density of liquid hydrogen of 70.9 kg/m³, the maximum loaded mass on the vessel with a capacity of 37,500 m³ is 2.66 kt per trip. During maritime transport, a quantity of LH₂ amounting to 0.2%/day is lost due to the boil-off phenomenon. It is assumed that the boil-off only happens during the cruising time with the bulk cargo on board. So, the boil-off rate accounts for 9 days of cruising. The mass of liquid hydrogen unloaded at the receiving terminal is calculated with equation 4.4.

$$\text{Unloaded mass} = \text{loaded mass} \cdot (1 - t_{\text{cruising}} * \text{BOG rate}) \quad (4.4)$$

This results in an unloaded liquid hydrogen mass of 2.59 kt per trip at the receiving terminal. The required annual hydrogen amount for the production of the assumed methanol capacity is ≈ 40 kt/year. To satisfy this demand, a total of 16 trips per year are required.

For the cost calculation of the shipping configurations analyzed in this study, a vessel time charter agreement is preferred over full vessel ownership. The literature of (Villalba-Herreros et al. 2023) considers a time charter agreement for a liquid hydrogen vessel with a capacity of 160,000 m³ that is able to transport liquid hydrogen for a charter rate of 90,000 USD₂₀₁₉/day (C_{charter}). A total of 15,000 USD₂₀₁₉ of non-proportional voyage cost are assumed per roundtrip per land terminal ($C_{\text{np,voyage}}$). As per loading and offloading, the facilities are included in the analysis of the logistic chain, therefore no additional tolls or fees are foreseen.

The values are scaled to the desired capacity of the ship, inflation adjusted to 2024 using CEPCI, and converted to euros. This results in $C_{\text{charter}} = 23,243$ €₂₀₂₄/day and $C_{\text{np,voyage}} = 18,595$ €₂₀₂₄/roundtrip.

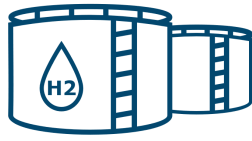
The cost associated with the chartering of the transport facility for liquid hydrogen is calculated with equation 4.2. Thus, the annual shipping cost of liquid hydrogen from Saudi Arabia to the Netherlands in this study is OPEX based and equals 11.1 M€₂₀₂₄/year.

LH₂ transport: Levelized Cost of Methanol

Upon establishing the OPEX value for the liquid hydrogen transport facility, the Levelized Cost of Methanol (LCOM) for this component can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, an OPEX of 11.1 M€ per year is considered for the transport facility of liquid hydrogen. Using these values, the LCOM for the liquid hydrogen transport component is calculated to be 55 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

Liquid hydrogen storage



Summary of results

Parameter	Value	Unit
Total capacity	87,600	m ³
CAPEX	306	M€
OPEX	31	M€/yr
LCOM	348	€/ton

Liquefied hydrogen is usually stored inside spherical tanks at about -252°C and pressure slightly above ambient pressure, 1.3 bar. These tanks are equipped from the inside with vacuum perlite to reduce the heat transfer, hence minimizing the losses due to the boil-off phenomenon.

Only the CAPEX related to purchasing the storage tank is considered for the storage of the LH₂. The OPEX is related to maintenance and insurance and accounts for 10% of the CAPEX. The losses due to boil-off are assumed to be negligible, as it is possible to re-liquefy the boil-off gas at the loading port.

At each operating terminal, it is necessary to establish a storage facility. The capacity of the storage tank is calculated with equation 4.3 and is computed considering the storage of the volume transported by the vessel increased by 10% as a safety margin for possible delays.

When using the ship capacity of (LH₂ Europe 2024) for liquid hydrogen transport, which equals 37,500 m³, the capacity of the tank will be equal to $V_{tank} = (1 + 0.1) \cdot 37,500 = 41,250\text{m}^3$.

According to the literature of (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024), an LH₂ storage tank with a capacity of 7300 m³ is used. Because storage tanks with such a big capacity, like 41.250 m³, are not realistic for liquid hydrogen storage yet, we assume the same tank capacity as this reference. Therefore, 6 tanks per terminal are purchased. Because storage at both terminals is required, the total storage capacity needed for liquid CO₂ is 87,600 m³.

For the cost assumption of the storage facility, the total installed costs exclude the land lease expenses. Thus, the total cost of this facility is solely based on the costs of the storage tanks.

For the cost calculation, the CAPEX from 1 storage tank in the literature of (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024) is used as a reference value. This storage tank with a capacity of 7300 m³, has a CAPEX that equals 26 M€₂₀₂₂. This value is inflation adjusted to 2024 using CEPCI, which results in a CAPEX of 25.5 M€₂₀₂₄ per tank. For the total 12 purchased tanks, the total CAPEX of the liquid hydrogen storage facility is 306 M€₂₀₂₄. Therefore, the OPEX of the liquid hydrogen storage facility is 31 M€₂₀₂₄/yr.

LH₂ storage: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the LH₂ storage units, the Levelized Cost of Methanol (LCOM) for these units can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 306 M€ and an OPEX of 31 M€ per year are considered for the storage units. Using these values, the LCOM for the LH₂ storage units is calculated to be 348 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

Liquid hydrogen gasification in the Netherlands



Summary of results

Parameter	Value	Unit
LH ₂ feed	40	kt/yr
H ₂ product	40	kt/yr
Electrical energy	0.75	GWh
Thermal energy	47	GWh
CAPEX	1.4	M€
OPEX	0.16	M€/yr
LCOM	2	€/ton

To make the hydrogen ready for the methanol process, the liquid hydrogen needs to be re-gasified. For the gasification step of the delivered liquid hydrogen, the reversion process from the literature of (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024) is used as a reference configuration. In this study, this plant is located in the Netherlands, and it is assumed that this plant operates continuously throughout the year.

The reversion from liquid to gaseous hydrogen consists of pumping and vaporization. In the case of hydrogen delivery to a hydrogen valley, where, for example, methanol is made, the pumping discharge pressure is set to 30 bar. In this case, a pump efficiency of 0.6 is assumed, and cooling water is assumed to be hot fluid in the vaporizer.

The reference configuration gasifies a quantity of 15.6 kt of hydrogen per year, under the conditions mentioned in table 4.4. In this study, 40 kt/y of hydrogen is required to produce the assumed quantity of methanol.

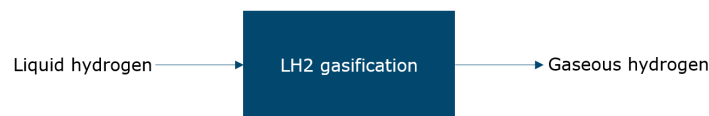


Figure 4.8: LH₂ gasification unit flowchart

The energy consumption for this hydrogen gasification process consists of 1.18 MWh/t_{H₂} of heating energy provided by cooling water of 30°C, and 19 kWh/t_{H₂} of electrical energy. In this study, an annual amount of 40 kt/yr of hydrogen is processed by the gasification unit. This gives a total energy consumption of 47 GWh of heat, and 0.75 GWh of electricity for the gasification process.

Stream	Flowrate	Conditions
Liquid hydrogen	40 kt/yr	1.3 bar, -247.9°C
Gaseous hydrogen	40 kt/yr	30 bar, 20°C

Table 4.4: Flow streams for the H₂ gasification unit

For the cost calculation, the CAPEX of the gasification process from the literature of (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024) is used as a reference value. This reference unit delivers 40 kt of hydrogen per year and has a CAPEX of 0.81 M€₂₀₂₂. This value is adjusted to 2024 using CEPCI and scaled with the six-tenths rule (3.1), which results in a CAPEX of 1.40 M€₂₀₂₄.

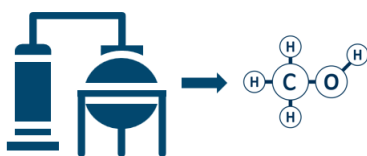
The fixed OPEX equals 2.4% of the CAPEX, which results in 0.03 M€₂₀₂₄/yr. The variable OPEX is calculated according to the energy utilities and equals 0.13 M€₂₀₂₄/yr. This results in a total OPEX of 0.16 M€₂₀₂₄/yr.

LH₂ gasification: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the LH₂ gasification unit, the Levelized Cost of Methanol (LCOM) for this unit can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 1.4 M€ and an OPEX of 0.2 M€ per year are considered for the gasification unit. Using these values, the LCOM for the LH₂ gasification unit is calculated to be 2.2 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

MeOH production in the Netherlands



Summary of results

Parameter	Value	Unit
H ₂ feed	40	kt/yr
CO ₂ feed	297	kt/yr
CH ₃ OH product	200	kt/yr
Electrical energy	70	GWh
Thermal energy	1.1	TWh
CAPEX	219	M€
OPEX	13	M€/yr
LCOM	203	€/ton

The methanol synthesis configuration employed for methanol production in the Netherlands utilizes the same reference configuration as used for the methanol production in Saudi Arabia described by (Cameli et al. 2024), which can be found in Section 4.1.1. For the purposes of this analysis, it is assumed that all calculated values remain consistent between the Netherlands and Saudi Arabia, except the OPEX, which differs due to variations in the cost of the utilities in each region.

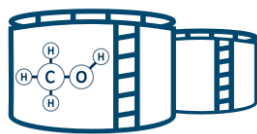
The fixed OPEX is 2.4% of the CAPEX (219 M€), which equals 5.25 M€₂₀₂₄/yr, and the variable OPEX is calculated with the consumed utilities and the assumed prices; this results in 7.42 M€₂₀₂₄/yr. The total OPEX of the methanol synthesis unit is 12.67 M€₂₀₂₄/yr.

E-MeOH production: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the methanol synthesis unit, the Levelized Cost of Methanol (LCOM) for this unit can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 219 M€ and an OPEX of 13 M€ per year are considered for the methanol synthesis unit. Using these values, the LCOM for the methanol synthesis unit is calculated to be 203 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

E-MeOH storage



Summary of results

Parameter	Value	Unit
Total capacity	176,000	m ³
CAPEX	45	M€
OPEX	4.5	M€/yr
LCOM	51	€/ton

The methanol storage configuration in this scenario is assumed to be identical to the one in Scenario 1, with the exception that it is halved, as only at one terminal a storage facility is required because the methanol isn't transported in this scenario. Detailed specifications and parameters for this configuration can be found in Section 4.1.1. This section provides comprehensive information on the storage infrastructure components considered in this research.

E-MeOH storage: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the methanol storage units, the Levelized Cost of Methanol (LCOM) for these units can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 45 M€ and an OPEX of 4.5 M€ per year are considered for the storage units. Using these values, the LCOM for the methanol storage units is calculated to be 51 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

4.1.3. Scenario 2b: H₂ import with NH₃

This section presents the results obtained from the analysis of the various infrastructure components in Scenario 2b of the E-methanol value chain considered in this study. Each component allows for specific design choices, which are explained in the subsequent subsections. Figure 4.9 illustrates the components of the E-methanol value chain considered in this Scenario, with the import of hydrogen via the hydrogen carrier ammonia from Saudi Arabia to the Netherlands.

In Saudi Arabia, hydrogen is produced and, together with nitrogen, fed to an ammonia synthesis plant and stored in temporary storage tanks. The liquid ammonia is then loaded onto an NH₃-carrying ship and transported to the Netherlands, where it is again temporarily stored in storage tanks. In the Netherlands, the ammonia is split back into its chemicals, hydrogen, and nitrogen, by a cracking plant. Locally captured CO₂ and the reconditioned hydrogen are fed into the methanol synthesis reactor. The synthesized methanol is temporarily stored near the production site before being distributed for further use across the country and its hinterlands.

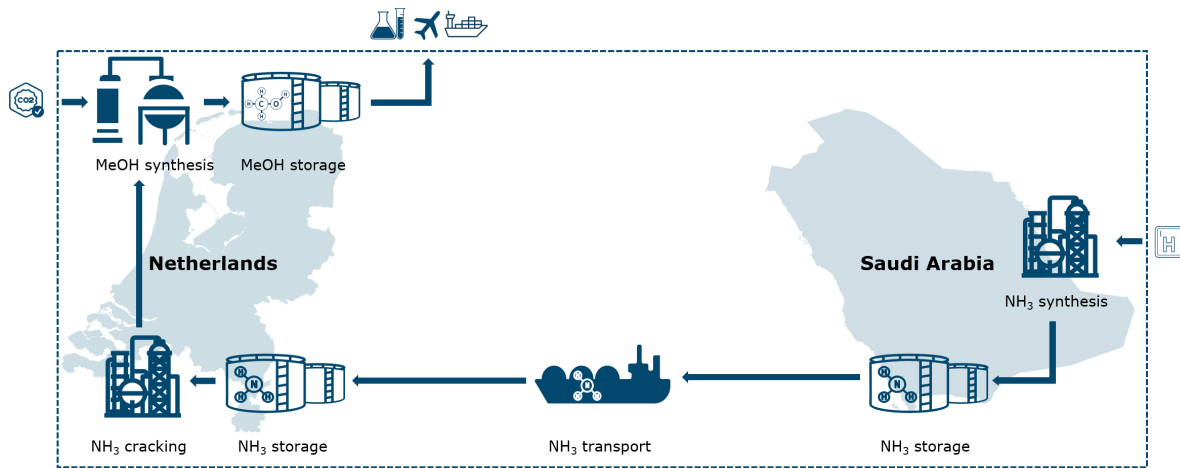


Figure 4.9: Components of Scenario 2b and its boundary conditions considered in this research

Summary of Scenario 2b

For the methanol synthesis at an annual production rate of 200 kt, this scenario necessitates the consumption of 50 kt of hydrogen and 297 kt of CO₂ per year. The value chain in this scenario requires a total of 150 GWh of electrical energy and 1.6 TWh of thermal energy annually. The total capital expenditure (CAPEX) for the value chain is 608 million €, while the total operational expenditure (OPEX) amounts to 46 million € per year. The annual costs for the feedstocks in this scenario are 227 M€/yr for hydrogen and 25 M€/yr for CO₂. Figure 4.10b represents the proportion of each category of expense related to the total cost.

The techno-economic analysis of this Scenario results in a total Levelized Cost of Methanol (LCOM). The additions of the LCOM for each component provide a comprehensive overview of the total cost across the entire value chain. This cumulative LCOM is illustrated using a waterfall diagram, shown in Figure 4.2a. The waterfall diagram breaks down and visualizes the contributions of each individual cost component. This offers a clear view of how each component adds to the overall cost within the value chain, and understanding these cost distributions is crucial for the identification of the key cost drivers and areas for potential optimization.

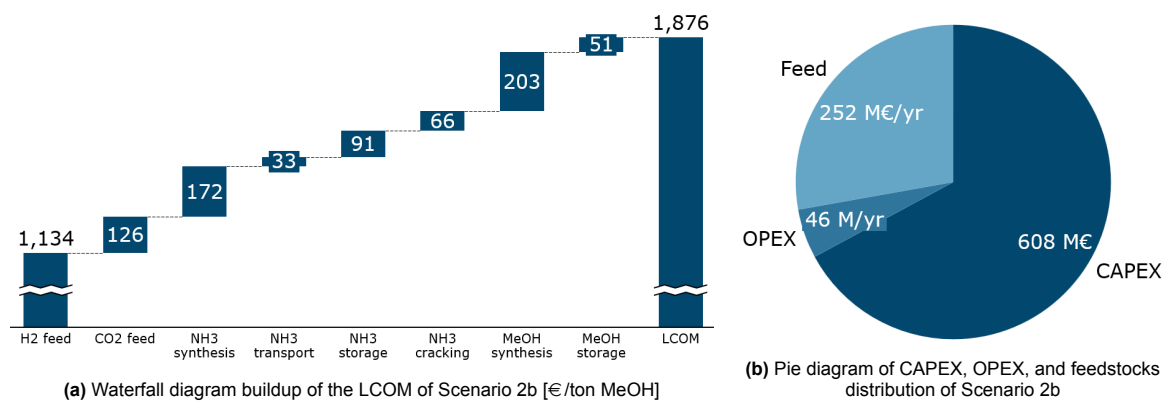


Figure 4.10

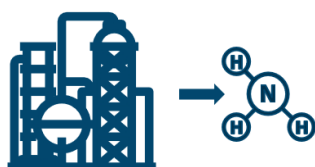
The total LCOM of Scenario 2b amounts to 1.9 € per kg of methanol produced. As shown in Figure 4.10a, the hydrogen feedstock emerges as the most significant contributor to the overall levelized cost. This highlights the substantial impact of hydrogen sourcing on the economic viability of the methanol production process.

When analyzing the costs associated with infrastructure components and conversion facilities, it becomes clear that the methanol production unit and the ammonia production unit of these components

have the highest expenditure. This indicates that these synthesis processes are major cost drivers within the value chain. The following subsections provide an in-depth examination of the components within this value chain, presenting both the technical and economic analyses for each component.

The elaboration of the calculated results for the different components considered in this value chain is explained in the following subsections.

Ammonia production in Saudi Arabia



Summary of results

Parameter	Value	Unit
H ₂ feed	50	kt/yr
NH ₃ product	283	kt/yr
Electrical energy	79	GWh
Thermal energy	543	GWh
CAPEX	178	M€
OPEX	12	M€/yr
LCOM	172	€/ton

The ammonia production plant considered in this study is located within the Arabian Gulf region and maintains an annual output of 283 kt of ammonia. For this plant, it is assumed that the plant operates continuously throughout the year.

An ammonia production process from the literature of (Mayer et al. 2023) is used as a reference configuration. This case study is based in Saudi Arabia. This ammonia production process consists of two main segments: an air separation unit (ASU), and ammonia synthesis with the Haber-Bosch process. The reference plant produces 555 kt NH₃/year and this reactor operates at a temperature of 550°C and a pressure of 200 bar.

For the ammonia synthesis plant with ASU, the flow streams considered are visualized in figure 4.11. The values for this production unit are converted to the production of the demanded amount of NH₃ and shown in table 4.5. The hydrogen used for the production of ammonia requires a higher purity than the hydrogen used for methanol production.



Figure 4.11: NH₃ production unit flowchart

Stream	Molar composition	Flowrate	Conditions
Hydrogen	100% H ₂	50kt/yr	30 bar, 60°C
Air	79% O ₂ , 21% N ₂	304 kt/yr	1 bar, 25°C
Ammonia	99.22% NH ₃ , 0.18% N ₂ , 0.60% H ₂	283 kt/yr (282.63 kt/yr NH ₃)	200 bar, -5°C

Table 4.5: Annual flow streams for the ammonia production unit

The energy consumption for the ammonia production process consists of 280 kWh/ t_{NH_3} electricity for the compressors, 890 kWh/ t_{NH_3} cooling energy provided by cooling water, 140 kWh/ t_{NH_3} cryogenic energy for the separation of nitrogen, and 890 kWh/ t_{NH_3} refrigerant energy for the ammonia separation.

The capacity of the ammonia production plant assumed in this study is 361 kt/yr. This gives a total energy consumption of 79 GWh for electricity, 252 GWh for cooling energy, 40 GWh for cryogenic energy, and 252 GWh for refrigerant energy.

For the cost calculation, the CAPEX from an ammonia synthesis unit from the literature of (Campion et al. 2023) is used as a reference value. This synthesis unit, together with an ASU, has a CAPEX of $4192\text{€}_{2019}/\text{capacity}$ (capacity in kg/h). The ammonia capacity in this study equals $32,300\text{ kg}_{\text{NH}_3}/\text{h}$. The value is inflation adjusted to 2024 using CEPCI and equals a CAPEX of 179 M€_{2024} .

The fixed OPEX equals 2.4% of the CAPEX, which results in $4.28\text{ M€}_{2024}/\text{yr}$. The variable OPEX is calculated according to the energy utilities and equals $7.46\text{ M€}_{2024}/\text{yr}$. Therefore, total OPEX results in $11.73\text{ M€}_{2024}/\text{yr}$.

NH₃ synthesis: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the ammonia synthesis unit, the Levelized Cost of Methanol (LCOM) for this unit can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 178 M€ and an OPEX of 12 M€ per year are considered for the synthesis unit. Using these values, the LCOM for the ammonia synthesis unit is calculated to be 172 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

Ammonia transport from SA to NL



Summary of results

Parameter	Value	Unit
Ship capacity	84,000	m ³
Trips per year	5	trips
OPEX	6.6	M€/yr
LCOM	33	€/ton

For the transportation section of ammonia from Saudi Arabia to the Netherlands, the methodology of (Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024) is employed. This methodology involves an LNG shipping vessel. The capacity of this vessel is based on the literature of (Villalba-Herreros et al. 2023) and equals $84,000\text{ m}^3$. The operational assumption for this vessel includes a cruising speed of approximately 26 km/h. The roundtrip time is calculated using the same method as in Section 4.1.1, and equals 29 days.

With a density of liquid ammonia of $682\text{ kg}/\text{m}^3$, the maximum loaded mass on the vessel with a capacity of $84,000\text{ m}^3$ is 57 kt/trip. During sea transport, (Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024) states that a quantity of ammonia equal to 0.1%/day is lost due to the boil-off phenomenon. In principle, the boil-off gas can be re-liquefied or used for power generation onboard; thus, for this reason, the boil-off principle for ammonia transport is neglected. Thus, the unloaded mass of ammonia after shipment is equal to the loaded mass of ammonia before shipment.

The required annual ammonia amount for the production of the assumed methanol capacity is $\approx 283\text{ kt}/\text{yr}$. To satisfy this demand, a total of 5 trips per year are required.

For the cost calculation of the shipping configurations analyzed in this study, a vessel time charter agreement is preferred over full vessel ownership. The literature of (Villalba-Herreros et al. 2023) considers a time charter agreement for an ammonia vessel with a capacity of $84,000\text{ m}^3$ that is able to transport liquid hydrogen for a charter rate of $36,282\text{ USD}_{2019}/\text{day}$ (C_{charter}). A total of $15,000\text{ USD}_{2019}$ of non-proportional voyage costs are assumed per roundtrip per land terminal ($C_{\text{np,voyage}}$).

As per loading and offloading, the facilities are included in the analysis of the logistic chain, therefore no additional tolls or fees are foreseen.

The values are inflation adjusted to 2024 using CEPCI, and converted to euros. This results in $C_{charter} = 44,977 \text{ €}_{2024}/\text{day}$ and $C_{np,voyage} = 18,595 \text{ €}_{2024}/\text{roundtrip}$.

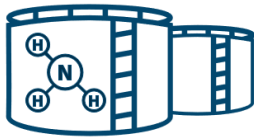
The cost associated with the chartering of the transport facility for ammonia is calculated with equation 4.2. Thus, the annual shipping cost of ammonia from Saudi Arabia to the Netherlands in this study is OPEX based and equals $6.6 \text{ M€}_{2024}/\text{year}$.

NH₃ transport: Levelized Cost of Methanol

Upon establishing the OPEX value for the ammonia transport facility, the Levelized Cost of Methanol (LCOM) for this component can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, an OPEX of 6.6 M€ per year is considered for the transport facility of liquid ammonia. Using these values, the LCOM for the ammonia transport component is calculated to be 33 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

Ammonia storage



Summary of results

Parameter	Value	Unit
Total capacity	188,000	m ³
CAPEX	80	M€
OPEX	8	M€/yr
LCOM	91	€/ton

Liquefied ammonia is usually stored at about -30°C and at a pressure slightly above atmospheric pressure, 1.3 bar, inside spherical tanks equipped with polyurethane foam insulation to limit losses due to the boil-off phenomenon.

Only the CAPEX related to purchasing the storage tank is considered for storing the liquefied ammonia. The OPEX related to maintenance and insurance is 10% of the CAPEX. The boil-off losses are assumed to be negligible.

At each operating terminal, it is necessary to establish a storage facility. The capacity of the storage tank is calculated with equation 4.3 and considers the storage of the volume transported by the ship V_{ship} increased by 10% as a safety margin to take into account any delay (Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024).

When using the ship capacity of (Villalba-Herreros et al. 2023) for liquid ammonia, the capacity is 84,000 m³. This gives a tank capacity of $V_{tank} = (1 + 0.1) \cdot 84,000 = 92,400 \text{ m}^3$.

It is proposed to divide this capacity by two and purchase two storage tanks per terminal, each with a capacity of 47,000 m³. Thus, there would be two storage tanks in Saudi Arabia and two in The Netherlands. Because storage at both terminals is required, the total storage capacity needed for liquid CO₂ is 188,000 m³.

For the cost assumption of the storage facility, the total installed costs exclude the land lease expenses. Thus, the total cost of this facility is solely based on the costs of the storage tanks.

For the cost calculation, the CAPEX from a storage tank in the literature from (Leighty et al. 2012) is used as a reference value. This storage tank with a capacity of 44,300 m³ has a CAPEX of 15 M\$₂₀₁₂. This value is inflation adjusted to 2024 using CEPCI, converted to euros, and scaled to the desired

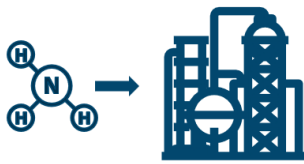
capacity with the six-tenths (3.1). The total CAPEX for the four needed storage tanks is 80.38 M€₂₀₂₄. Therefore, the OPEX for the ammonia storage facility is 8.04 M€/year.

NH₃ storage: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the ammonia storage units, the Levelized Cost of Methanol (LCOM) for these units can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 80 M€ and an OPEX of 8 M€ per year are considered for the storage units. Using these values, the LCOM for the ammonia storage units is calculated to be 91 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

Ammonia cracking in the Netherlands



Summary of results

Parameter	Value	Unit
NH ₃ feed	283	kt/yr
H ₂ product	40	kt/yr
Electrical energy	0.66	GWh
CAPEX	87	M€
OPEX	2	M€/yr
LCOM	66	€/ton

To meet the hydrogen demand specified for the methanol synthesis unit targeted production rates, as outlined in Section 4.1.1, the capacity of the ammonia cracking process in this study was determined to be ≈ 40 kt hydrogen per year.

An ammonia cracking plant from the literature of (Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024) is used as a reference plant for the ammonia cracking process considered in this study. This ammonia-to-H₂ plant produces 12.5 kt of hydrogen per year at 30 bar.

In this process, the ammonia stream is compressed and preheated in a train of heat exchangers and sent to the cracking reactor. The heat duty required for the cracking reaction is supplied by burning part of the fed ammonia. No external fuel is needed since ammonia combustion with air is used to sustain the endothermicity of the cracking reaction. Air is used as an oxidizer to ensure complete combustion. Downstream the reaction stage, the separation of the hydrogen product from the unconverted ammonia and nitrogen is performed via pressure swing adsorption (PSA). Next to the heat supplied by burning part of the ammonia in this process, the only utility is electricity, with a consumption of 16.6 MWh/kt_{H₂}.

For the fired ammonia cracker in this study, the flow streams considered are visually shown in figure 4.12 and the corresponding annual flow rates are shown in table 4.6. Around 20% of the produced hydrogen is burned for the heat supply for the cracking process, this approach eliminates the need for an external heat source.

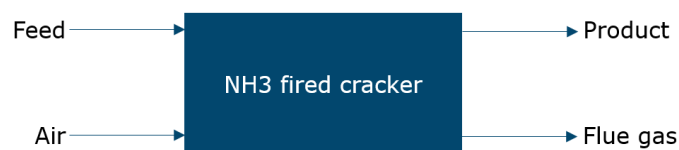


Figure 4.12: NH₃ fired cracker flowchart

Stream	Molar composition	Flowrate	Conditions
Feed	100% NH ₃	283 kt/yr	1.3 bar, -27.6°C
Air	79%N ₂ , 21% O ₂	492 kt/yr	1 bar, 25°C
Product	99.9% H ₂ , 0.01% N ₂	40 kt/yr	30 bar, 25.5°C
Flue gas	H ₂ , N ₂ , H ₂ O, NO, O ₂ mix	734 kt/yr	1 bar, 139°C

Table 4.6: Annual flow streams for the fired ammonia cracker

The energy consumption of the ammonia cracking process is 16.7 kWh/ t_{H_2} delivered. This energy consumption only consists of electrical energy. The ammonia cracker in this study delivers 40 kt of hydrogen annually, this gives an annual energy consumption of 0.66 GWh of electrical energy.

For the cost calculation, the CAPEX from the ammonia cracker from the literature of (Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024) is used as a reference value. This unit delivers 12.5 kt of hydrogen annually and has a CAPEX of 44.14 M€₂₀₂₂. This value is inflation adjusted to 2024 according to CEPCI and scaled with the six-tenths rule(3.1) to the production rate of 40 kt/yr. Then, the CAPEX for the ammonia cracking unit equals 87.32 M€₂₀₂₄.

The fixed OPEX equals 2.4% of the CAPEX, which results in 2.09 M€₂₀₂₄/yr. The variable OPEX is calculated according to the utilities, which only includes the utility of the electricity and results in a value of 0.06 M€₂₀₂₄/yr. Therefore, the total OPEX results in 2.15 M€₂₀₂₄/yr.

NH₃ cracking: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the ammonia cracking unit, the Levelized Cost of Methanol (LCOM) for this unit can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 87 M€ and an OPEX of 2 M€ per year are considered for the cracking unit. Using these values, the LCOM for the ammonia cracking unit is calculated to be 66 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

E-MeOH production and storage

Since the components involved in methanol production and handling in Scenario 2 are consistent across all three hydrogen import cases examined in this study, the analysis of methanol synthesis and storage is consolidated in Section 4.1.2 and 4.1.2. This section provides a comprehensive evaluation of these processes.

The LCOM of the methanol production unit in the Netherlands results in 203 €/ton MeOH and the LCOM for the storage of methanol in this Scenario results in 51 €/ton MeOH

4.1.4. Scenario 2c: H₂ import with LOHC

This section presents the results obtained from the analysis of the various infrastructure components in Scenario 2c of the E-methanol value chain considered in this study. Each component allows for specific design choices, which are explained in the subsequent subsections. Figure 4.13 illustrates the components of the E-methanol value chain considered in this Scenario, with the import of hydrogen via a liquid organic hydrogen carrier (LOHC) from Saudi Arabia to the Netherlands.

In Saudi Arabia, hydrogen is produced is fed to a hydrogenation unit where an LOHC is hydrogenated. After this process, the hydrogenated LOHC is stored in temporary storage tanks. The hydrogenated LOHC is then loaded onto a LOHC-carrying ship and transported to the Netherlands, where it is again temporarily stored in storage tanks. In the Netherlands, the LOHC is de-hydrogenated by a de-hydrogenation plant. The de-hydrogenated LOHC is also temporarily stored at this location before this substance is shipped back to Saudi Arabia for further hydrogenation later. Locally captured CO₂ and the reconditioned hydrogen are fed into the methanol synthesis reactor. The synthesized methanol is temporarily stored near the production site before being distributed for further use across the country and its hinterlands.

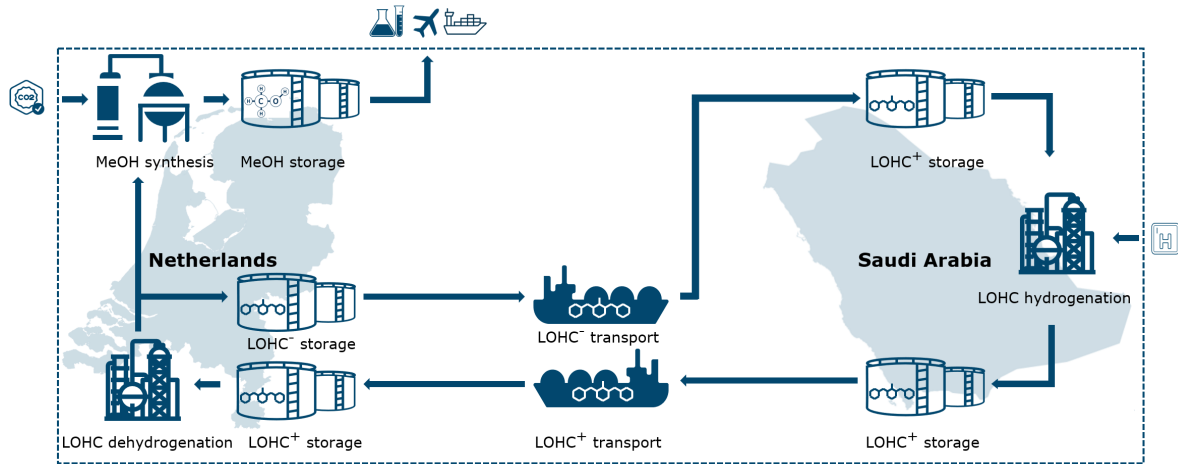


Figure 4.13: Components of Scenario 2c and its boundary conditions considered in this research

Summary of Scenario 2c

For the methanol synthesis at an annual production rate of 200 kt, this scenario necessitates the consumption of 62 kt of hydrogen and 297 kt of CO₂ per year. The value chain in this scenario requires a total of 220 GWh of electrical energy and 1.9 TWh of thermal energy annually. The total capital expenditure (CAPEX) for the value chain is 419 million €, while the total operational expenditure (OPEX) amounts to 54 million € per year. The annual costs for the feedstocks in this scenario are 278 M€/yr for hydrogen and 25 M€/yr for CO₂. Figure 4.14b represents the proportion of each category of expense related to the total cost.

The techno-economic analysis of this Scenario results in a total Levelized Cost of Methanol (LCOM). The additions of the LCOM for each component provide a comprehensive overview of the total cost across the entire value chain. This cumulative LCOM is illustrated using a waterfall diagram, shown in Figure 4.14a. The waterfall diagram breaks down and visualizes the contributions of each individual cost component. This offers a clear view of how each component adds to the overall cost within the value chain, and understanding these cost distributions is crucial for the identification of the key cost drivers and areas for potential optimization.

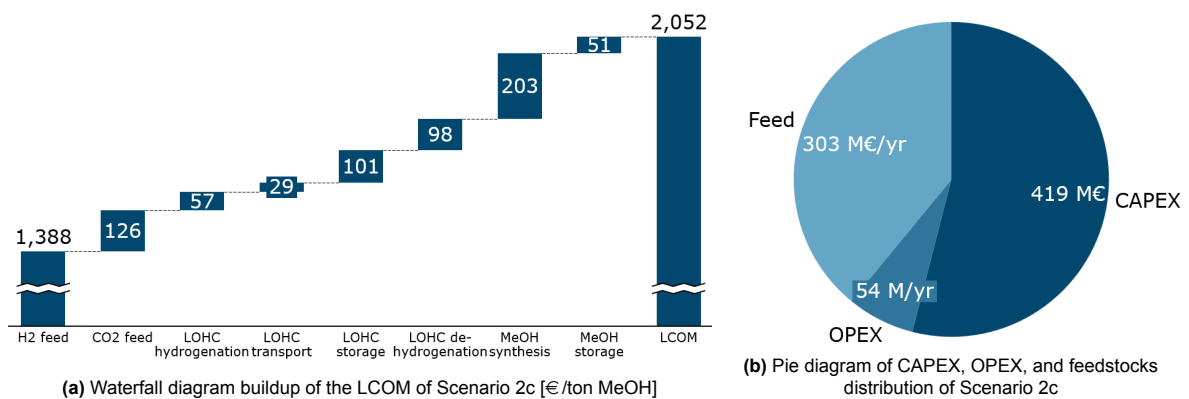


Figure 4.14

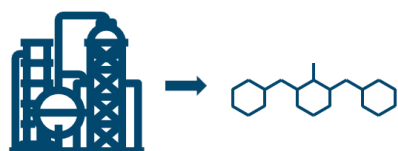
The total LCOM of Scenario 1 amounts to 2.1 € per kg of methanol produced. As shown in Figure 4.14a, the hydrogen feedstock emerges as the most significant contributor to the overall levelized cost. This highlights the substantial impact of hydrogen sourcing on the economic viability of the methanol production process.

When analyzing the costs associated with infrastructure components and conversion facilities, it be-

comes clear that the methanol production unit of these components has the highest expenditure. This indicates that the methanol synthesis itself is a major cost driver within the value chain. The following subsections provide an in-depth examination of the components within this value chain, presenting both the technical and economic analyses for each component.

The elaboration of the calculated results for the different components considered in this value chain is explained in the following subsections.

LOHC hydrogenation in Saudi Arabia



Summary of results

Parameter	Value	Unit
H ₂ feed	62	kt/yr
H0-DBT feed	970	kt/yr
H18-DBT product	1.0	Mt/yr
Electrical energy	22	GWh
Thermal energy	581	GWh
CAPEX	20	M€
OPEX	9	M€/yr
LCOM	57	€/ton

For the hydrogenation step of the LOHC dibenzyltoluene (DBT), the configuration from (Spatolisano, Restelli, et al. 2024) is used. In this study, this plant is located within Saudi Arabia and maintains the hydrogenation of 62 kt of hydrogen per year. For this plant, it is assumed that the plant operates continuously throughout the year.

According to the literature of (Spatolisano, Restelli, et al. 2024), this hydrogenation reactor operates at a pressure of 35 bar and a temperature of 210°C, and the corresponding exothermic reaction is shown in equation 4.5. The organic carrier used, H0-DBT, coming from the unloading terminal, is mixed with a make-up stream (whose flow rate is very limited), pumped and heated, and then routed to the reactor. This reactor is fed with this dibenzyltoluene stream, a hydrogen stream, and a nitrogen stream.

A complete hydrogen conversion within the reactor is assumed, which eliminates the need for a recycle loop. The separation section downstream of the reactor is simplified in this case: hydrogen conversion is quantitative, and byproduct formation in the reaction phase is negligible. In this case, the reaction heat is used from steam production from boiler feed water. The reaction product, consisting of the hydrogenated species, is cooled and then stored to be transported to the unloading terminal.



For the hydrogenation unit for H0-DBT, the flow streams considered are visualized in figure 4.15. The values corresponding to these flow streams are converted to the production of the final demanded amount of hydrogen at the end of the value chain for the methanol production, and shown in table 4.7. Although not required for a hydrogenation reaction, this configuration uses nitrogen as a thermal diluent to control the reaction exothermicity. This regulates the reaction temperature, which creates a safer reaction environment.

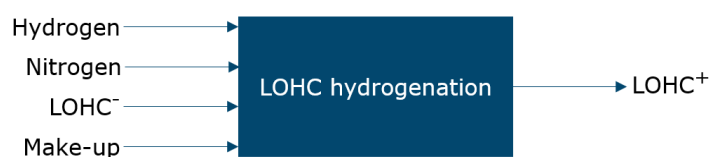


Figure 4.15: LOHC hydrogenation flowchart

Stream	Molar composition	Flowrate	Conditions
Hydrogen	100% H ₂	61.71 kt/yr	20 bar, 25°C
Nitrogen	100% N ₂	13.45 kt/yr	35 bar, 20°C
LOHC-	95.97% H0-DBT, 3.97% H18-DBT, 0.06% H ₂	969.1 kt/yr	1.01 bar, 25°C
Make-up	100% H0-DBT	0.94 kt/yr	1.01 bar, 25°C
LOHC+	0.26% H0-DBT, 99.51% H18-DBT, 0.23% N ₂	1031.35 kt/yr	1.01 bar, 50°C

Table 4.7: Annual flow streams for the LOHC hydrogenation plant

The hydrogenation process consumes 268 kWh/t_{H₂} for cooling with cooling water, 351 kWh/t_{H₂} of electricity is consumed, and 9.15 MWh/t_{H₂} is generated by the reaction in the form of heat.

In this study, an annual amount of 62 kt/yr of hydrogen is used for the hydrogenation process. This gives a total annual energy consumption of 17 GWh for cooling, 22 GWh for electricity, and 654 GWh is generated by the exothermic reaction in the form of heat.

For the cost calculation, the CAPEX from the hydrogenation unit in the literature of (Spatolisano, Restelli, et al. 2024) is used as a reference value. This unit uses 15.8 kt hydrogen per year and has a CAPEX of 8.98 M€₂₀₂₂. This value is inflation adjusted to 2024 and scaled with the six-tenths rule to the desired amount of hydrogen. This results in a CAPEX of 20.0 M€₂₀₂₄. This CAPEX also includes buying the H0-DBT coming from the unloading port.

The fixed OPEX equals 2.4% of the CAPEX, which results in 0.48 M€₂₀₂₄/yr. The variable OPEX is calculated according to the utilities: the energy consumption, the annual amount of make-up H0-DBT needed, and the consumed amount of nitrogen. The values for the prices of H0-DBT and nitrogen are obtained from the literature of (Spatolisano, Restelli, et al. 2024), and used for the variable OPEX calculation, this values are inflation adjusted using CEPCI and shown in table 4.8. The variable OPEX equals 8.35 M€₂₀₂₄/yr, which gives a total OPEX of 8.83 M€₂₀₂₄/yr.

Parameter	Value	Unit
C_{H0-DBT}	4,904	€ ₂₀₂₄ /ton
C_{N2}	0.196	€ ₂₀₂₄ /m ³

Table 4.8: Assumptions for the LOHC hydrogenation OPEX calculation (Spatolisano, Restelli, et al. 2024)

LOHC hydrogenation: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the LOHC hydrogenation unit, the Levelized Cost of Methanol (LCOM) for this unit can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 20 M€ and an OPEX of 9 M€ per year are considered for the hydrogenation unit. Using these values, the LCOM for the LOHC hydrogenation unit is calculated to be 57 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

LOHC transport from SA to NL



Summary of results

Parameter	Value	Unit
Ship capacity	87,000	m ³
Trips per year	13	trips
OPEX	5.7	M€/yr
LCOM	29	€/ton

For the transportation section of the LOHC from Saudi Arabia to the Netherlands, the methodology of (Spatolisano, Restelli, et al. 2024) is employed. According to this methodology, the first step is calculating the time for one round trip. The roundtrip time is calculated using the same method as in Section 4.1.1, and equals 29 days while cruising with a speed of 26 km/h.

The required capacity of the ship is calculated using the round trip time. When one round trip has a duration of 29 days, a maximum of $365/29 \approx 13$ trips can be completed annually. This study assumes that the same ship is used for the hydrogenated and dehydrogenated LOHC. Because the weight of the hydrogenated and dehydrogenated differs, the largest volume of these two will be the volume of the vessel.

- H0-DBT: With a transportable amount of 969 kt of H0-DBT per year, the loaded amount of H0-DBT per trip must be at least 75 kt. With a density of 1040 kg/m^3 , the volume of the ship must be $\approx 72.000 \text{ m}^3$.
- H18-DBT: With a transportable amount of 1030 kt of H18-DBT per year, the loaded amount of H18-DBT per trip must be at least 79 kt. With a density of 910 kg/m^3 , the volume of the ship must be $\approx 87.000 \text{ m}^3$.

The literature of (Schuler et al. 2024) states that ships suitable for LOHC transportation, have a capacity ranging from 40 to 120 kt. This verifies that both capacities are realistic to use. To make one vessel suitable for both shifts, the largest volume of 87.000 m^3 is chosen.

For the cost calculation of the shipping configurations analyzed in this study, a vessel time charter agreement is preferred over full vessel ownership. Due to the compatibility of LOHC storage and transport with existing infrastructure for fossil fuels, similar to methanol, the same reference time charter configuration utilized for methanol transport is applied to this LOHC transport configuration.

The literature of (Meca et al. 2022) considers a time charter agreement for a methanol vessel with a capacity of $120,000 \text{ m}^3$ that is able to transport methanol for a charter rate of $19,000 \text{ USD}_{2021}/\text{day}$ ($C_{charter}$). A total of $15,000 \text{ USD}_{2021}$ of non-proportional voyage costs are assumed per roundtrip per land terminal ($C_{np,voyage}$). As per loading and offloading, the facilities are included in the analysis of the logistic chain, therefore no additional tolls or fees are foreseen.

The values are scaled to the desired capacity of the ship, inflation adjusted to 2024 using CEPCI, and converted to euros. This results in $C_{charter} = 14,636 \text{ €}_{2024}/\text{day}$ and $C_{np,voyage} = 15,937 \text{ €}_{2024}/\text{roundtrip}$.

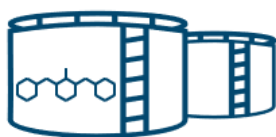
The cost associated with the chartering of the transport facility for LOHC is calculated with equation 4.2. Thus, the annual shipping cost of LOHC from Saudi Arabia to the Netherlands in this study is OPEX based and equals $5.7 \text{ M€}_{2024}/\text{year}$.

LOHC transport: Levelized Cost of Methanol

Upon establishing the OPEX value for the LOHC transport facility, the Levelized Cost of Methanol (LCOM) for this component can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, an OPEX of 5.8 M€ per year is considered for the transport facility of the LOHC. Using these values, the LCOM for the LOHC transport component is calculated to be 29 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

LOHC storage



Summary of results

Parameter	Value	Unit
Total capacity	349,800	m ³
CAPEX	88	M€
OPEX	8.8	M€/yr
LCOM	101	€/ton

According to (Abdin et al. 2021), LOHCs can be stored for an extended period at a large scale without any losses. Regarding storing the hydrogenated and dehydrogenated LOHC, for H0-DBT and H18-DBT, different tank sizes are used, and only the CAPEX related to the purchase of the storage tanks is considered. The OPEX is related to maintenance and insurance and accounts for 10% of the CAPEX. During storage of LOHC losses will be negligible (Spatolisano, Restelli, et al. 2024).

Both terminals need storage facilities for temporary storage of the hydrogenated and dehydrogenated LOHC. Therefore, two storage facilities in the Netherlands and two storage facilities in Saudi Arabia are considered.

The required capacity of these storage tanks is calculated with equation 4.3 and is computed considering the storage of the volume transported by the vessel increased by 10% as a safety margin for possible delays.

- In the case of storing the hydrogenated LOHC, when using the full ship capacity of 87,000 m³, the total capacity of the storage tanks needs to be equal to $V_{tank} = (1 + 0.1) \cdot 87,000 = 95,700 \text{ m}^3$.
- In the case of storing the dehydrogenated LOHC, when only $\approx 72,000 \text{ m}^3$ of the vessel is used, the total capacity of the storage tanks needs to be equal to $V_{tank} = (1 + 0.1) \cdot 72,000 = 79,200 \text{ m}^3$.

Therefore, a total volume of 174,900 m³ needs to be stored at both terminals. One of the advantages of hydrogen storage via LOHC is the compatibility with existing storage and transport infrastructure for liquid fossil fuels. According to (Niermann et al. 2019), the investment costs of the conventional oil storage tanks, which are suitable to use for LOHC storage due to their similar physical and chemical properties, amount to 192 €₂₀₁₉/m³.

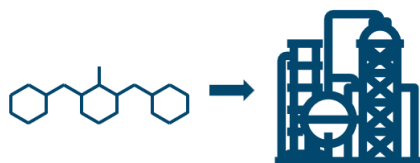
When adjusting this value to 2024 with CEPCI and multiplying this with the total volume multiplied by two because of the storage at both terminals, the CAPEX for the LOHC storage facility in this study equals 89 M€₂₀₂₄. With this CAPEX, the total OPEX of the LOHC storage facility equals 8.9 M€₂₀₂₄/yr.

LOHC storage: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the LOHC storage units, the Levelized Cost of Methanol (LCOM) for these units can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 88 M€ and an OPEX of 8.8 M€ per year are considered for the storage units. Using these values, the LCOM for the LOHC storage units is calculated to be 101 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

LOHC dehydrogenation in the Netherlands



Summary of results

Parameter	Value	Unit
H18-DBT feed	1.0	Mt/yr
H ₂ product	40	kt/yr
H0-DBT product	969	kt/yr
Thermal energy	165	GWh
Electrical energy	847	GWh
CAPEX	48	M€
OPEX	13	M€/yr
LCOM	98	€/ton

For the dehydrogenation step of the hydrogenated LOHC perhydrodibenzyltoluene, also the configuration of (Spatolisano, Restelli, et al. 2024) is used. In this study, this plant is located in the Netherlands and delivers 40 kt of hydrogen annually for methanol production. For this plant, it is assumed that the plant operates continuously throughout the year.

According to the configuration of (Spatolisano, Restelli, et al. 2024), the H18-DBT is pumped and routed to the reaction section. The reactor works at 320°C and 1.1 bar and the corresponding reaction is shown in equation 4.6. The outlet product mixture, composed of H0-DBT and hydrogen, undergoes a sequence of separations downstream of the reaction section. The outlet has to be stored and routed back to the loading terminal, while produced hydrogen, is compressed and routed to the methanol plant site.



Since the dehydrogenation reaction is highly endothermic, the heat of the reaction is supplied by burning part of the hydrogen produced. Thus, no external heat has to be provided. This stream is routed to the combustion section, and here the hydrogen stream is preheated by heat exchange to its auto-ignition temperature and burned. In figure 4.16, the flow streams are visualized, and part of the hydrogen stream is visibly routed back to the combustion section.

An alternative option for the heat supply in this process is the utilization of waste heat rather than burning a portion of the hydrogen. This method is also suitable due to the relatively low temperatures required for this reaction, particularly when compared to the higher temperatures necessary for the cracking of ammonia, where using waste heat isn't an option.

The values corresponding to these flow streams are converted to the production of the final demanded amount of hydrogen delivered to the methanol plant, which equals 39.94 kt per year. The segment of the hydrogen stream for combustion constitutes 22.03 kt of hydrogen per year.

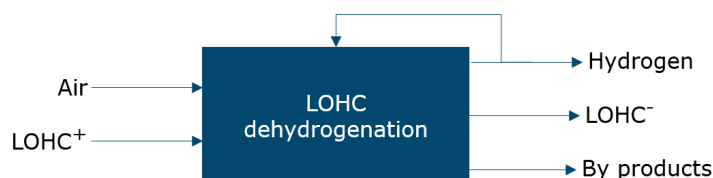


Figure 4.16: LOHC dehydrogenation flowchart

Stream	Molar composition	Flowrate	Conditions
Air	79% N ₂ , 21% O ₂	791.25 kt/yr	1.01 bar, 30°C
LOHC ⁺	0.26% H ₀ -DBT, 99.51% H ₁₈ -DBT, 0.23% N ₂	1031.35 kt/yr	1.01 bar, 25°C
Hydrogen	99.91% H ₂ , 0.03% N ₂	39.94 kt/yr	30 bar, 50.73°C
LOHC ⁻	95.97% H ₀ -DBT, 3.97% H ₁₈ -DBT, 0.06% H ₂	969.1 kt/yr	1.01 bar, 35°C
By products	65.92% N ₂ , 0.97% O ₂ , 33.11% H ₂ O	813.21 kt/yr	1.01 bar, 171.79 °C

Table 4.9: Annual flow streams for the LOHC dehydrogenation unit

The energy consumption for this dehydrogenation process consists of 4.14 MWh/t_{H₂} of cooling energy provided by cooling water, 17.0 MWh/t_{H₂} of heat provided by burning part of the hydrogen, and 3.23 MWh/t_{H₂} of electrical energy. In this study, an annual amount of 40 kt/yr of hydrogen is delivered after the dehydrogenation process. This gives a total energy consumption of 165 GWh for cooling, 682 GWh for heating, and 129 GWh for electricity.

For the cost calculation, the CAPEX of the dehydrogenation unit from the literature of (Spatolisano, Restelli, et al. 2024) is used as a reference value. This reference unit delivers 10.2 kt of hydrogen per year and has a CAPEX of 21.4 M€₂₀₂₂. This value is inflation adjusted to 2024 and scaled with the six-tenths rule to the desired amount of hydrogen. This results in a CAPEX of 47.8 M€₂₀₂₄.

The fixed OPEX equals 2.4% of the CAPEX, which results in 1.14 M€₂₀₂₄/yr. The variable OPEX is calculated according to the utilities: the energy consumption for cooling and electricity. The variable OPEX equals 12.3 M€₂₀₂₄/yr, which gives a total OPEX of 13.45 M€₂₀₂₄/yr.

LOHC dehydrogenation: Levelized Cost of Methanol

Upon establishing the conceptual CAPEX and OPEX values for the dehydrogenation synthesis unit, the Levelized Cost of Methanol (LCOM) for this unit can be calculated using the assumed lifetime, discount rate, and methanol capacity. These parameters are detailed in Section 3.2.2. The equation for calculating the LCOM is provided in Section 3.2.2.

In this analysis, a CAPEX of 48 M€ and an OPEX of 13 M€ per year are considered for the dehydrogenation unit. Using these values, the LCOM for the LOHC dehydrogenation unit is calculated to be 98 € per ton of methanol produced. This calculation integrates the initial capital expenditure, ongoing operational costs, the projected economic lifespan of the unit, the discount rate, and the annual methanol capacity providing a comprehensive cost metric for the methanol production process.

E-MeOH production and storage

Since the components involved in methanol production and handling in Scenario 2 are consistent across all three hydrogen import cases examined in this study, the analysis of methanol synthesis and storage is consolidated in Section 4.1.2 and 4.1.2. This section provides a comprehensive evaluation of these processes.

The LCOM of the methanol production unit in the Netherlands results in 203 €/ton MeOH and the LCOM for the storage of methanol in this Scenario results in 51 €/ton MeOH

4.2. Comparison of scenarios

After obtaining the results for the various scenarios, a comprehensive comparison of the different scenarios is conducted to identify the most cost-effective and efficient approach for methanol production. This Section will dive into the evaluation of the base case and show the findings from the sensitivity analysis performed.

4.2.1. Evaluation of the base-case

The following two Sections present a detailed comparison of the base-case scenarios for methanol production from a technical, and economic point of view.

Technical comparison

The technical parameters considered in this study are the mass balances, production capacities, and energy consumption. The results of the technical analyses are summarized per scenario in Table 4.10.

Parameter	Specification	Sc1	Sc2a (LH ₂)	Sc2b (NH ₃)	Sc2c (LOHC)
Feed	H ₂	40 kt	41 kt	50 kt	62 kt
	CO ₂	305 kt	297 kt	297 kt	297 kt
Energy	Electrical	101 GWh	412 GWh	150 GWh	220 GWh
	Thermal	1.1 TWh	1.5 TWh	1.6 TWh	1.3 TWh

Table 4.10: Technical analysis annual results per scenario

Comparatively, Scenario 1 has the lowest hydrogen requirement at 40 kt per year, while Scenario 2c has the highest at 62 kt per year. All scenarios, except Scenario 1, require 297 kt per year of CO₂, with Scenario 1 requiring slightly more at 305 kt per year. In terms of energy consumption, Scenario 1 is the most efficient, with the lowest electrical energy consumption at 101 GWh per year and the lowest thermal energy consumption at 1081 GWh per year. Scenario 2a, in contrast, has the highest electrical energy consumption at 412 GWh per year, whereas Scenario 2b has the highest thermal energy consumption at 1.6 TWh per year. This thermal energy is derived from externally supplied sources; therefore, any heat generated by the combustion of a portion of the product is not accounted for in Table 4.10.

Logistical and operational considerations also play a crucial role in the overall efficiency and cost-effectiveness of each scenario. Scenario 1 includes two transportation stages, which may increase complexity and logistical costs. In Scenarios 2a, 2b, and 2c, hydrogen is imported in different forms, each with unique processing and conversion processes that affect overall efficiency and costs.

For the methanol process itself, a quantity of 40 kt of hydrogen and 297 kt of CO₂ annually is needed. When knowing this value and the hydrogen feedstock quantity at the beginning of the chain, the hydrogen efficiency of each scenario can be calculated. For Scenario 1, this is 100% because the hydrogen is directly used for methanol synthesis. In Scenario 2a, the hydrogen efficiency is 97.4%, which means that 2.6% of the hydrogen is lost along the chain. Scenario 2b has an efficiency of 79.3%, so 20.7% is lost. Scenario 2c has the lowest efficiency of 64.7%, with a loss of 35.3%. When considering the losses of CO₂, only in Scenario 1 2.4% of the CO₂ is lost along the chain.

The relatively higher hydrogen losses in both the ammonia and LOHC scenarios are due to the reason that the heat needed for the ammonia cracking and LOHC dehydrogenation steps is supplied by burning part of the hydrogen. Especially for the LOHC scenario, where the efficiency is relatively high, this hydrogen loss will decrease if a better heat integration system is applied.

The comparative analysis of the technical results highlights that Scenario 1, despite its logistical complexities and minor CO₂ losses, is the most energy-efficient option in both electrical and thermal energy consumption. Furthermore, this scenario has the lowest hydrogen loss compared to the other scenarios.

Economic comparison

The economic parameters calculated in the previous Sections of this study are the CAPEX, OPEX, and the LCOM. The calculated values are presented in Table 4.11. The CAPEX and OPEX values presented in this table encompass all the components within the value chains, excluding the feedstock costs. The feedstock cost values are mentioned separately in this table.

Parameter	Sc1	Sc2a (LH ₂)	Sc2b (NH ₃)	Sc2c (LOHC)
CAPEX	362 M€	772 M€	608 M€	419 M€
OPEX	31 M€/yr	91 M€/yr	46 M€/yr	54 M€/yr
Feedstocks	206 M€/yr	210 M€/yr	252 M€/yr	303 M€/yr
LCOM	1,414 €/ton	1,997 €/ton	1,876 €/ton	2,052 €/ton

Table 4.11: Economic analysis annual results per scenario

The economic comparison of the four scenarios reveals significant variations in CAPEX, OPEX, and annual feedstock costs, which collectively influence the overall cost-effectiveness of each scenario. Scenario 1 demonstrates the lowest CAPEX of 362 M€ and the lowest OPEX of 31 M€/yr, also the

annual feedstock costs are the lowest with 206 M€/yr. This scenario presents a cost-effective approach due to its minimal initial investment and operational costs, despite the logistical complexities. Scenario 2a has the highest CAPEX of 772 M€, and the highest OPEX of 91 M€/yr. Although the cost of the components in the value chain is the highest, the feedstock costs are relatively low compared to the other scenarios. The CAPEX and OPEX values of Scenario 2b and 2c are moderate values between these upper and lower values, with a CAPEX of 608 M€ and 419 M€, and an OPEX of 46 M€/yr and 54 M€/yr, respectively. However, in both Scenarios 2b and 2c, the feedstock costs are substantially higher with a value of 252 M€/yr and 303 M€/yr, respectively.

Based on the results presented in Section 4.1, the final LCOM for the four scenarios in the base case can be assessed. Specifically, the LCOM for Scenario 1 is 1.4 €/kg MeOH, for Scenario 2a it is 2.0 €/kg MeOH, for Scenario 2b it amounts to 1.9 €/kg MeOH, and for Scenario 2c, the LCOM is 2.1 €/kg MeOH. This makes Scenario 1 the best choice among these different scenarios, followed by Scenario 2b, 2a, and 2c in respective order. Figure 4.17 illustrates these values, demonstrating the absolute differences in LCOM across the various scenarios. This comparison highlights the scale of variation in cost efficiency among the different scenarios.

In Section 3.2.2, an accuracy margin of $\pm 50\%$ has been established for CAPEX values, and an accuracy margin of $\pm 10\%$ has been set for OPEX values. The detailed analysis of the accuracy margin and the corresponding results are presented in a figure in Appendix B.

When the accuracy margins are applied, the ranking among the scenarios shifts at the upper limit of the accuracy ranges. When the accuracy margin of $+50\%$ CAPEX and $+10\%$ OPEX are applied, the liquid hydrogen import becomes the least cost-effective option. This shows a difference compared to the base case, where the import of LOHC is the least cost-effective scenario. This accuracy analysis reveals the dependency of each scenario on CAPEX and OPEX. Scenario 2a exhibits the highest dependency on CAPEX and OPEX, as indicated by the significant range between the upper and lower LCOM values. This high sensitivity is primarily due to the substantial infrastructure costs associated with hydrogen storage and liquefaction.

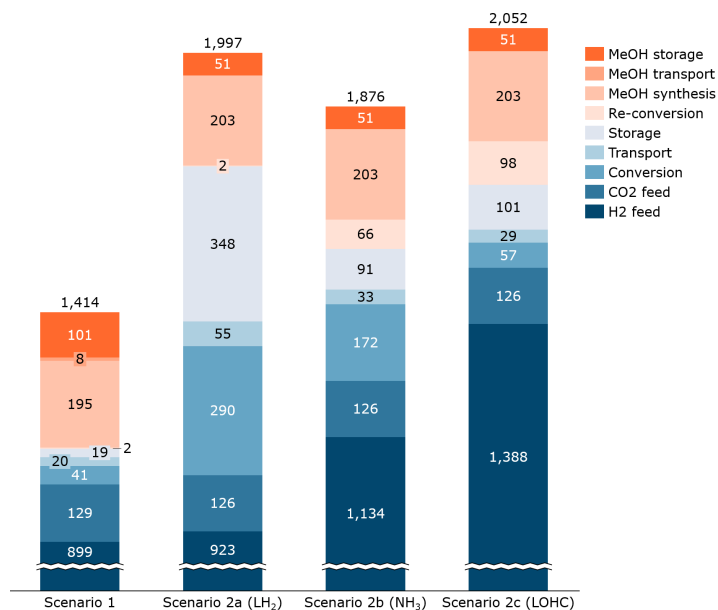


Figure 4.17: Comparison of the results of the base-case Scenarios [€/ton MeOH]

While the optimal choice in the base case is determined based on the total LCOM results, the primary objective of this Section, given the comparative nature of this study, is to identify and analyze the components that distinguish these scenarios from one another. Emphasis will be placed on identifying the unique elements and variations within each scenario contributing to the different characteristics and outcomes.

E-methanol vs. grey methanol

When comparing these LCOM values to the current market price of grey methanol, which fluctuates between 400 and 500 USD/ton as reported by the Methanol Institute (MI 2024a), it is evident that the values for E-methanol obtained in this study are significantly higher. This deviation raises the critical question of whether E-methanol can eventually become competitive with grey methanol. In the chemical industry, where cost is a primary driver, this appears unlikely without significant technological advancements or cost reductions in green methanol production.

However, in new methanol applications, such as the maritime and aviation sectors, regulatory mandates are driving the adoption and willingness to pay for renewable fuels. These industries are subject to regulations requiring a certain percentage of their fuel consumption to be derived from renewable sources of non-biological origin (green hydrogen-based fuels) (Marques 2021). This regulatory framework creates a market for E-methanol despite its higher production costs, as meeting these mandates is mandatory and if not, is met with strict penalties. The environmental benefits and regulatory pressures thus play a crucial role in the potential competitiveness of E-methanol in these sectors, even if it remains costlier than grey methanol.

E-methanol vs. bio-methanol

(IRENA 2021a) compared the production costs of E-methanol and bio-methanol. The study presents a wide range for current bio-methanol prices, from 330 to 1,000 USD/ton, and a projected range of 230 to 880 USD/ton when mature production levels are achieved in the future.

The study by IRENA also indicates that the current production costs for E-methanol range from 820 to 1,620 USD/ton, with a significant projected decrease to 250 to 630 USD/ton in the future. This substantial reduction in E-methanol production costs is expected because of the anticipated decrease in electricity costs.

The LCOM of Scenario 1, identified as the most economical option in this study, falls within the current range for E-methanol production. The IRENA study demonstrates lower costs for bio-methanol. However, despite the currently lower costs, bio-methanol production is limited by the availability of feedstock, which hinders the industry from achieving economies of scale. In contrast, if large-scale production is the ultimate goal, this is more feasible with E-methanol.

Comparison to literature

The total LCOM values are compared to the existing literature in this Section to assess their competitiveness and feasibility. According to (Cameli et al. 2024), the LCOM for E-MeOH in 2050 is 1,265 €/ton, including a PEM electrolyzer, DAC unit, and E-MeOH synthesis unit. Scenario 1 in this research, with an LCOM of 1,414 €/ton, is the closest to this projection, which suggests it could be a competitive option with further technological advancements and cost reductions.

(Antwerpen et al. 2023) estimates an LCOM of 1,646 AUS\$/ton (approximately 1,040 €/ton), considering standalone renewable energy farms, electrolytic hydrogen generation, carbon capture, and CO₂ hydrogenation to methanol. This cost is significantly lower than the LCOMs for Scenarios 2a, 2b, and 2c in this research, indicating that the feedstocks, renewable energy infrastructure, and process efficiencies assumed in the study from (Antwerpen et al. 2023) might be more optimized or benefit from specific regional advantages.

The study by (IRENA 2021a) indicates current production cost levels for E-methanol with CO₂ from combined renewable sources ranging from 750 €/ton to 1,500 €/ton). This range encompasses the LCOM for Scenario 1 but is significantly lower than the LCOMs for the other scenarios. This suggests that the scenarios with higher LCOMs might need to address specific inefficiencies or higher input costs to become competitive.

(Battaglia et al. 2021) reports that the LCOM for green methanol using hydropower as a renewable energy source spans from 874 € to 1,356 €/ton, including electrolyzer and carbon capture unit costs. This range is slightly below the LCOM for Scenario 1 and well below the LCOMs for Scenarios 2a, 2b, and 2c, indicating that hydropower might offer a cost advantage over the renewable energy sources considered in this research.

4.2.2. Main cost drivers

To clearly understand the main differences between the scenarios, the main cost drivers are identified by analyzing Figure 4.17. For each Scenario, the components contributing to the LCOM are classified according to their contribution in decreasing order. In other words, the largest contributor is number one. This is summarized in Table 4.12, and the first four contributors of each scenario are defined as the main cost drivers and are discussed in the next sections.

The designation of a component as a large cost driver does not necessarily imply a significant influence on selecting the optimal scenario. If this component's absolute values and relative contributions are nearly identical across scenarios, its impact on the decision-making process becomes practically negligible. In other words, when this component is ignored, the outcome of the comparison won't change. In such cases, other factors and cost components exhibit greater variability and influence and will play a more important role in determining the most favorable scenario.

Contributor	Scenario 1	Scenario 2a (LH ₂)	Scenario 2b (NH ₃)	Scenario 2c (LOHC)
#1	H ₂ feed	H ₂ feed	H ₂ feed	H ₂ feed
#2	MeOH synthesis	LH ₂ storage	MeOH synthesis	MeOH synthesis
#3	CO ₂ feed	H ₂ liquefaction	NH ₃ synthesis	CO ₂ feed
#4	MeOH storage	MeOH synthesis	CO ₂ feed	LOHC storage
#5	CO ₂ liquefaction	CO ₂ feed	NH ₃ storage	LOHC dehydrogenation
#6	LCO ₂ transport	LH ₂ transport	NH ₃ cracking	LOHC hydrogenation
#7	LCO ₂ storage	MeOH storage	MeOH storage	MeOH storage
#8	MeOH transport	LH ₂ gasification	NH ₃ transport	LOHC transport
#9	LCO ₂ gasification			

Table 4.12: Classification of the contribution of the different components to the total LCOM for each scenario

Hydrogen feed

It is very noticeable that the hydrogen feed significantly contributes the most to the LCOM in each of the scenarios, establishing it as the major cost driver. When examining the relative contribution of the hydrogen feed to the total LCOM, it is calculated that it accounts for 64% in Scenario 1, 46% in Scenario 2a, 60% in Scenario 2b, and 66% in Scenario 2c.

This analysis shows a notable deviation in Scenario 2a, where the contribution of the hydrogen feed is substantially lower compared to the other three scenarios. This suggests that Scenario 2a has distinct cost dynamics compared to the others.

Another significant observation regarding the LCOM of the hydrogen feed is that the total LCOM of Scenario 1 is only 26 €/ton higher than the LCOM of the hydrogen feed from Scenario 2c, while the contribution of the hydrogen feed to the total LCOM in both scenarios are almost identical. This indicates a substantial difference in the total cost of both scenarios, with Scenario 1's total LCOM being approximately 2/3 of the size of Scenario 2c.

Methanol synthesis unit

Another component that is noted to be a large cost driver in each scenario is the methanol synthesis unit. For Scenario 1, Scenario 2b, and Scenario 2c, this is the second-largest cost driver. This unit has a contribution to the total LCOM of 195 €/ton in Scenario 1, and a contribution of 203 €/ton for Scenario 2a, 2b, and 2c.

Although these values are the same for almost all four scenarios, the relative contribution can be examined to test the influence on the outcome. It accounts for 14% in Scenario 1, 10% in Scenario 2a, 11% in Scenario 2b, and 10% in Scenario 2c. Scenario 1 has a small deviation in the relative contribution to the others. Because the contribution of the methanol synthesis is more or less constant among the scenarios, this component is almost non-influenceable in the decision for the best scenario.

It is noted that, in Scenario 2a, the methanol synthesis unit is not the second-largest cost driver. This deviation is attributed to the substantially higher cost of liquid hydrogen storage in Scenario 2a compared to the storage facilities in the other scenarios. The next Section dives into the storage units.

Storage unit

A remarkable contributor in Scenario 2a is the storage component for the liquid hydrogen. This storage unit has a substantially higher value compared to the other storage components considered in the scenarios. This larger LCOM accounts for the fact that the storage facility for liquid hydrogen requires more technical complexity. For example, these storage tanks require sophisticated insulation systems to maintain extremely low temperatures to keep hydrogen in its liquid state.

The relative contribution of liquid hydrogen storage to the total LCOM of Scenario 2a is 17%. A large deviation is seen when comparing this to the other hydrogen carrier storage facilities. The storage of ammonia and the storage of LOHC contributes in both Scenario 2b and 2c to 5% of the total LCOM. In Scenario 1, the storage of liquid CO₂ only contributes to 1% of the total LCOM.

If looking at the methanol storage, it is noted that this component is constant among the different variants of Scenario 2. For Scenario 1, this value is twice as large because this scenario requires methanol storage facilities at two terminals instead of 1. The methanol storage component relatively contributes 7% in Scenario 1 and 3% in Scenario 2a and 2b, and 2% in Scenario 2c to the total LCOM. This indicates the methanol storage unit isn't a large contributor to the total LCOM.

The sizing of storage units in this study is directly influenced by the capacities of the vessels used for transporting the considered substances. To ensure enough capacity and operational flexibility, the volumes of the storage tanks are designed to be 10% larger than the volumes of the vessels. Consequently, when a vessel with a larger volume is employed, the total storage volume must also be increased, leading to higher costs for the storage facility. Conversely, if a smaller vessel is utilized, the total storage volume required is reduced, resulting in lower associated costs for the storage facility.

Moreover, the cost dynamics of transport facilities are inversely related to vessel size. Utilizing larger vessels decreases the frequency of roundtrips needed to transport the same quantity, thereby reducing transport costs. Conversely, the use of smaller vessels necessitates more roundtrips, increasing the overall transport costs. When further research could be done, the optimization point between the cost of shipping and the cost of storage could be examined.

Conversion unit

The conversion unit refers to CO₂ liquefaction in Scenario 1 and the conversion from hydrogen to its different carriers in Scenario 2a, 2b, and 2c. Since the different conversion components have different characteristics, the values of the conversion units have a large deviation among the different Scenarios. This fact makes this unit an interesting component in the decision between the considered scenarios.

In Scenario 1, the liquefaction of CO₂ has an LCOM of only 41 €/ton with a relative contribution of 3%. In Scenario 2a, the liquefaction of H₂ has an LCOM of 290 €/ton and a relative contribution of 14%, which makes this the third-largest contributor to the total LCOM in this Scenario. Also, in Scenario 2b, the conversion unit, which consists of ammonia synthesis, is the third-highest contributor with 172 €/ton with a relative contribution of 9%. In Scenario 2c, the hydrogenation of the LOHC has an LCOM of 57 €/ton with a relative contribution of 3%.

An additional observation is the fact that the re-conversion units exhibit substantially lower costs compared to the conversion units across all scenarios. The re-conversion units include the gasification of liquid CO₂, the gasification of liquid hydrogen, the cracking of ammonia, and the dehydrogenation of the LOHC for the respective scenarios. Specifically, the gasification processes for both liquid CO₂ and liquid hydrogen have an LCOM of only 2 €/ton, indicating that these processes contribute negligibly to the overall cost chain.

Particularly in Scenario 2a, the difference between the costs of conversion and re-conversion is significant, with a decrease of 99.4%. In Scenario 2b, the LCOM for re-conversion is 66 €/ton, and in Scenario 2c, this value equals 98 €/ton.

CO₂ feed

Despite the fact that the kt of CO₂ required for methanol synthesis are substantially greater than the amount of hydrogen, the LCOM for the CO₂ feed is significantly lower than for the hydrogen feed. Nevertheless, the CO₂ feed remains a major cost driver in three of the four scenarios considered.

Across almost all scenarios, the CO₂ feed LCOM has an equal value of 126 €/ton. Only in Scenario 1 this value is slightly higher and equals 129 €/ton. The relative contribution of the CO₂ feed to the total LCOM is 9% in Scenario 1, 6% in Scenario 2a, 7% in Scenario 2b, and 6% in Scenario 2c.

4.2.3. Hydrogen carrier comparison

This Section focuses on the alternative within Scenario 2 to assess the different methods of importing hydrogen. To compare the hydrogen carrier options, the values are translated into the Levelized Cost of Hydrogen (LCOH). The LCOH represents the effective cost per kilogram of hydrogen when arriving in the Netherlands. This also provides the price at which hydrogen would need to be produced domestically to achieve comparable economic outcomes. The LCOH of the different hydrogen import options is shown in Figure 4.18.

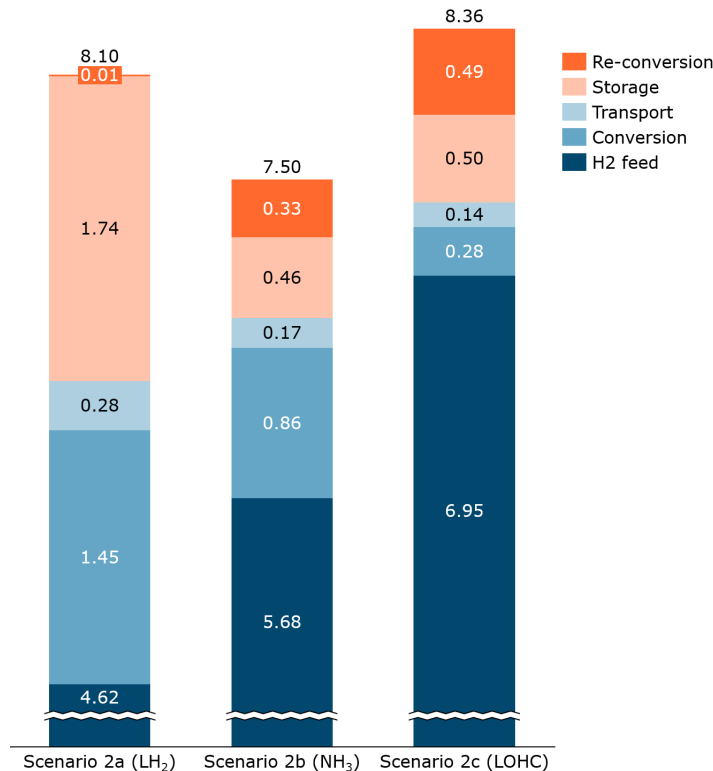


Figure 4.18: Comparison of the resulted LCOH of the different hydrogen carriers considered in Scenario 2 [€/kg H₂]

The primary cost driver in each scenario is the hydrogen feedstock, with variations arising from the differing hydrogen losses incurred along the respective value chains. Scenario 2a, which involves importing liquid hydrogen, has a total LCOH of 8.10 €/kg. The conversion component and storage component in this scenario have both a significantly higher value compared to the other components in the chains. However, the re-conversion step is substantially smaller than the other scenarios. Scenario 2b has a total LCOH of 7.5 €/kg, which is the lowest among the three options. Besides the hydrogen feed, this LCOH is mainly driven by the conversion to ammonia. Scenario 2c exhibits the highest LCOH among the three scenarios, with a value of 8.36 €/kg. The cost components for storage and conversion within this chain are relatively equal distributed.

The elevated feedstock costs in Scenario 2c are related to the use of hydrogen for heat supply in the dehydrogenation process, resulting in an approximate 35% loss of hydrogen. An alternative heat supply option is the utilization of waste heat instead of burning a portion of the hydrogen. This approach is viable due to the relatively low temperatures required for this reaction. Implementing this exergy optimization strategy could enhance the cost-efficiency of the LOHC scenario.

The calculated LCOH provides a critical benchmark for determining the cost efficiency of hydrogen production strategies in the Netherlands. This LCOH serves as an indicator of the threshold hydrogen

price at which local production becomes economically viable. According to this study, if hydrogen could be produced in the Netherlands below 7.50 €/kg, importing it from Saudi Arabia becomes economically unfavorable.

To give some perspective to these numbers, a comparison to existing literature is done. A research group published three papers, which each covers the value chain of the same hydrogen carriers as used in this study, each value chain uses the same input amount of hydrogen of 43.2 t/d and the transport distance is 2,500 km. These three papers are compared to the outcome of this study. The build-up LCOH of these value chains are presented in Figure 4.19, the road transport components are neglected for the comparison because they're not considered in this study.

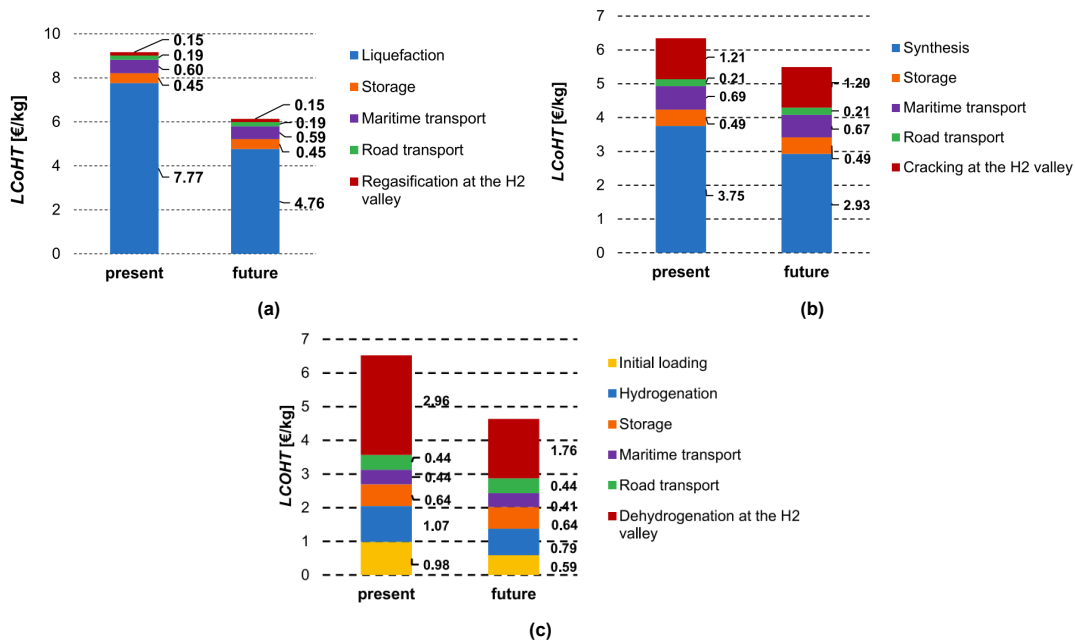


Figure 4.19: LCOH of hydrogen import value chains in the form of (a) Liquid Hydrogen (Restelli, Spatolisano, Pellegrini, Cattaneo, et al. 2024) (b) Ammonia (Restelli, Spatolisano, Pellegrini, Angelis, et al. 2024) (c) LOHC (Spatolisano, Restelli, et al. 2024)

The LCOH values from these sources are presented in an acceptable range compared to the values reported in this study. Additionally, the proportional contributions of the components in these sources align well with the proportional contributions of the components in this study. However, the studies by Restelli and Spatolisano present a different ranking of hydrogen carriers, indicating that the LOHC scenario seems to be the most cost-effective option, followed by ammonia and liquid hydrogen.

For the liquid hydrogen scenario in this study, the LCOH is nearly the same as the Restelli and Spatolisano are showing for the present scenario. A closer examination of specific components reveals that the biggest difference is the relative contribution of liquid hydrogen storage to the total LCOH is significantly smaller in the study compared to this study. In Restelli's study, the total number of roundtrips made by the vessel transporting liquid hydrogen is double that of this study, due to the use of relatively smaller vessels. Consequently, the transport facility costs are relatively higher than the storage facility costs in Restelli's analysis. Conversely, this study necessitates a much larger storage facility to accommodate the liquid hydrogen for extended periods, resulting in substantially higher storage facility costs.

If examining the ammonia scenario, the LCOH from Restelli's analysis is also lower than the LCOH from liquid hydrogen. In both studies, synthesis is identified as the largest cost driver among the processes. Notably, the storage configuration in Restelli's study has the lowest cost contribution, as opposed to being the second largest contributor in this study. Conversely, transport configuration costs are higher in Restelli's study. This discrepancy can be attributed to the number of round trips made versus the storage capacity. Additionally, the cracking of ammonia is a relatively larger cost contributor in Restelli's

study if compared to this study. One reason for this could be that Restelli's study delivers almost one-third of the hydrogen amount delivered in this study. Given that a scaling factor of 0.6 is used, economies of scale are present, making it more cost-effective to produce larger amounts.

The most significant variation in the LCOH is observed in the LOHC scenario. In Restelli's analysis, the LCOH for LOHC is approximately equivalent to that of ammonia and lower than that of liquid hydrogen. However, in this study, the LCOH for LOHC is higher than both the ammonia and liquid hydrogen scenarios. The primary reason for this discrepancy is the high contribution of feedstock costs in the LOHC scenario of this study. Restelli's analysis utilizes the same initial amount of hydrogen in the value chains, while this study compares scenarios where the outputs of the value chains are equivalent. Another notable difference is that the dehydrogenation configuration in Restelli's study contributes significantly more to the overall cost compared to this study. This disparity can also be explained by the presence of economies of scale.

Another study from Roland Berger also examined the supply chains of these three hydrogen carriers between the Arabian Gulf region and Rotterdam (Weichenhain 2021). The build-up of the obtained LCOH values from Roland Berger is illustrated in Figure 4.20.

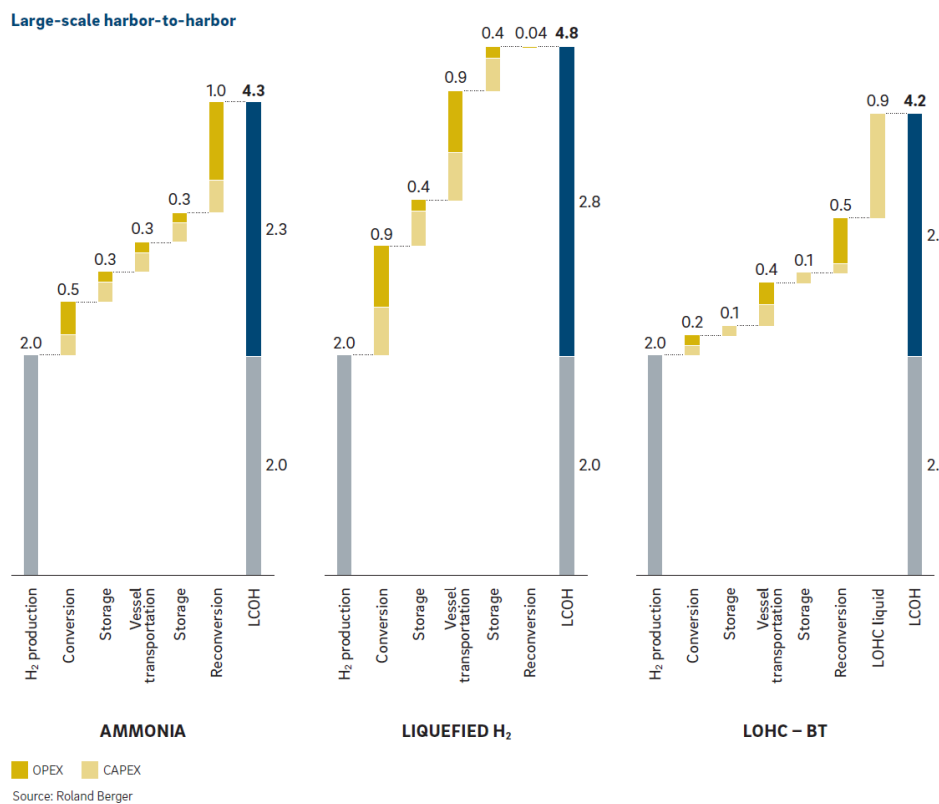


Figure 4.20: The LCOH breakdown from the different hydrogen carriers from Roland Berger in 2025 [€/kg H₂] (Weichenhain 2021)

Although the differences in these values are very small, Roland Berger's study also shows that importing LOHC is the cheapest, followed by ammonia and liquid hydrogen. Comparing these results to the results from this study, it is noted that the hydrogen production in the Roland Berger study has an equal contribution in each scenario. They use the same amount of hydrogen input in the value chains.

In this study, the hydrogen output of the value chains is equal in each scenario. Due to the different hydrogen efficiencies among the carriers, the amount of hydrogen input is different among the scenarios and that could be a reason for the deviation in ranking compared to the studies from Roland Berger and Restelli and Spatolisano. If the contribution of feedstock costs were excluded from the LCOH results in this study, the ranking of the scenarios would align with that of the Roland Berger study

The study from Roland Berger shows that, especially for liquid hydrogen, that the separate components are almost all evenly contributing to the total LCOH. This is very different compared to the results in this study, where the components' LCOH values have a very wide range.

4.3. Sensitivity analysis

The impact of several variables on the LCOM is evaluated via sensitivity analysis. In this Section, the results of this sensitivity analysis are elaborated, which are conducted according to the methodology as explained in Section 3.3. Table 4.13 and 4.14 summarize the obtained LCOM results evaluated by the 'low,' 'base,' and 'high' cases, which values can be found in Table 3.5.

H ₂ price				
Case	Sc1	Sc2a (LH ₂)	Sc2b (NH ₃)	Sc2c (LOHC)
Low	815	1,382	1,121	1,126
Base	1,414	1,997	1,876	2,052
High	2,013	2,612	2,632	2,978

CO ₂ price				
Case	Sc1	Sc2a (LH ₂)	Sc2b (NH ₃)	Sc2c (LOHC)
Low	1,307	1,893	1,772	1,948
Base	1,414	1,997	1,876	2,052
High	1,521	2,101	1,980	2,156

Table 4.13: Summary of the results from the sensitivity analysis performed on the H₂ and CO₂ feedstock prices, LCOM in [€/ton MeOH]

Shipping distance				
Case	Sc1	Sc2a (LH ₂)	Sc2b (NH ₃)	Sc2c (LOHC)
Low	← 1,997 →			
Base	1,414	1,997	1,876	2,102
High	1,433	2,059	1,899	2,120

MeOH capacity				
Case	Sc1	Sc2a (LH ₂)	Sc2b (NH ₃)	Sc2c (LOHC)
Low	1,635	2,604	2,148	2,172
Base	1,414	1,997	1,876	2,052
High	1,340	1,803	1,790	1,999

Table 4.14: Summary of the results from the sensitivity analysis performed on the shipping distance and methanol capacity, LCOM in [€/ton MeOH]

4.3.1. Hydrogen feedstock price

This Subsection explains the outcomes of the sensitivity analysis by varying the hydrogen feedstock price. In the base case in this study, the hydrogen feedstock price equals 4.5€/kg. A 'low case' and a 'high case' price are determined in Section 3.3 and set to 1.5€/kg and 7.5€/kg, respectively.

The LCOM outcomes for the defined cases and the different scenarios are shown in Table 4.15. To give a more visualized overview of the behavior of the LCOM in the different scenarios when the hydrogen price is varied, all the prices in a range from 1€/kg to 10€/kg are plotted in a graph in Figure 4.21. The corresponding exact values can be found in Appendix C, Figure C.1.

Case	Scenario 1	Scenario 2a (LH ₂)	Scenario 2b (NH ₃)	Scenario 2c (LOHC)
1.5€/kg	815	1,382	1,121	1,126
4.5€/kg	1,414	1,997	1,876	2,052
7.5€/kg	2,013	2,612	2,632	2,978

Table 4.15: Results of the sensitivity analysis for the hydrogen feedstock price, LCOM in [€/ton MeOH]

The graph in Figure 4.21 illustrates the sensitivity of the hydrogen feedstock price on the LCOM and reveals three critical intersection points. The points indicate shifts in the ranking of the scenarios based on the hydrogen price. Firstly, evaluating the graph from a low hydrogen price to a high hydrogen price, the first intersection point is observed at approximately 1.4 €/kg. When the price of hydrogen becomes higher than 1.4 €/kg, scenario 2c (which involves LOHC import) becomes more expensive than scenario 2b (which involves NH₃ import).

At approximately 4 €/kg the second intersection point is found. Beyond this price, Scenario 2c becomes more expensive than Scenario 2a (which involves liquid hydrogen import). This shift suggests that Scenario 2a becomes more cost-effective compared to Scenario 2c as the hydrogen price increases beyond this threshold.

The second intersection point is identified at approximately 7 €/kg. At this price, Scenario 2b becomes more expensive than Scenario 2a. This indicates that the cost advantage of importing ammonia decreases compared to importing liquid hydrogen as the hydrogen price passes 7 €/kg.

The analysis highlights a notable shift in the cost ranking of the scenarios with varying hydrogen feedstock prices. Notably, Scenario 1 consistently remains the most cost-effective option among the four scenarios, maintaining the lowest LCOM across the entire range of hydrogen prices considered. This suggests that Scenario 1 is the most robust and economically viable choice under fluctuating hydrogen prices.

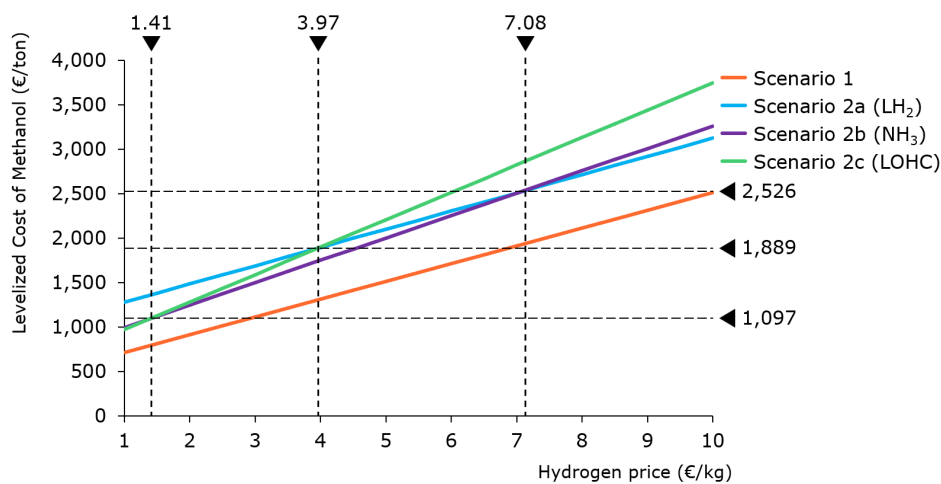


Figure 4.21: Hydrogen price sensitivity analysis results in graph

4.3.2. CO₂ feedstock price

This Subsection explains the outcomes of the sensitivity analysis by varying the other feedstock required for methanol production; CO₂. In the base case in this study, the hydrogen feedstock price equals 85€/ton. The defined low- and high-cases in this analysis are 15€/ton and 155 €/ton, respectively.

The outcomes for the defined cases are shown in Table 4.16. To give a more visualized overview of the behavior of the LCOM, all the values in a range from 10€/ton to 155€/ton are plotted in a graph in Figure 4.22. The corresponding exact values can be found in Appendix C, Figure C.2.

Case	Scenario 1	Scenario 2a (LH ₂)	Scenario 2b (NH ₃)	Scenario 2c (LOHC)
15€/ton	1,307	1,893	1,772	1,948
85€/ton	1,414	1,997	1,876	2,052
155€/ton	1,521	2,101	1,980	2,156

Table 4.16: Results of the sensitivity analysis for the CO₂ feedstock price, LCOM in [€/ton MeOH]

The graph in Figure 4.22 illustrates the sensitivity of the CO₂ feedstock price on the LCOM across the

four different scenarios. It is observed that as the CO₂ price increases, the LCOM for all scenarios shows a steady increase. This indicates that higher CO₂ prices directly translate to a higher LCOM across all scenarios.

Throughout the range of CO₂ prices considered, Scenario 1 consistently remains the most cost-effective option. Scenario 2b is the second most cost-effective choice, followed by Scenario 2a, and lastly Scenario 2c. Because each scenario increases evenly and no intersection points are exhibited, the ranking of scenarios based on varying CO₂ prices remains consistent across the range.

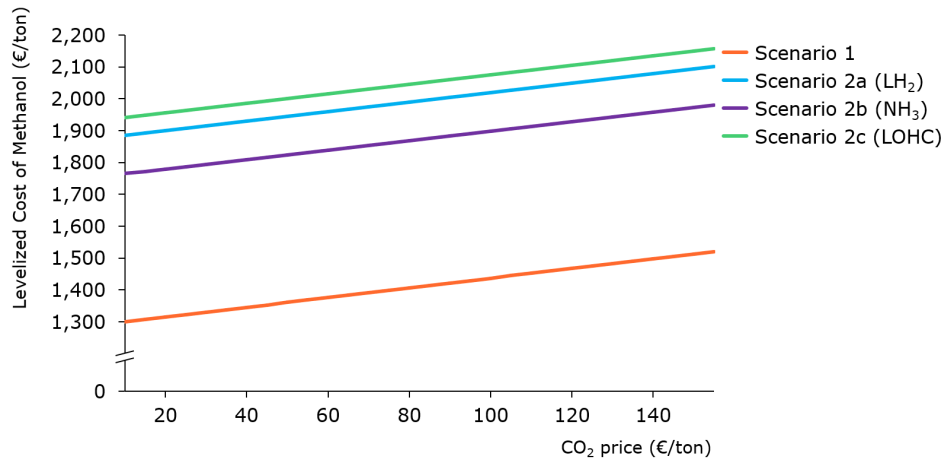


Figure 4.22: CO₂ price sensitivity analysis results in graph

4.3.3. Shipping distance

This Subsection explains the outcomes of the sensitivity analysis by varying the shipping distance. In the base case, a shipping distance of 7,500 km is considered. For the low case, a shipping distance of 0 km is assumed, with methanol production taking place in the Netherlands utilizing locally sourced hydrogen and CO₂ which eliminates the presence of multiple scenarios. Conversely, the high case involves a shipping distance of approximately double the length of the base case, amounting to 14,000 km. This route represents the maritime distance between Chile and the Netherlands. Although the shipping components in the value chains have a relatively minor influence on the total LCOM, it is valuable to analyze the effects of variations in this component.

The outcomes for the defined cases are shown in Table 4.17.

Case	Scenario 1	Scenario 2a (LH ₂)	Scenario 2b (NH ₃)	Scenario 2c (LOHC)
0 km			←1,997→	
7,500 km	1,414	1,997	1,876	2,052
14,000 km	1,433	2,059	1,899	2,071

Table 4.17: Results of the sensitivity analysis for the shipping distance, LCOM in [€/ton MeOH]

E-Methanol production in the Netherlands with locally sourced feedstocks

In the low case, only a single scenario is considered, where methanol is produced domestically in the Netherlands using locally sourced hydrogen and CO₂. The value chain components for methanol production in this case include solely the methanol synthesis process and its feedstocks, and the methanol storage facility, therefore hydrogen carriers are not relevant in this case. As can be found in Section 4.1.2, the LCOM for E-methanol production in the Netherlands is 203 €/ton MeOH. The LCOM for the methanol storage in the Netherlands is 51 €/ton MeOH. The base case price for CO₂ is still used, as the CO₂ is already sourced from the Netherlands in the base case, the LCOM of the CO₂ feed equals 126 €/ton MeOH.

Before determining the hydrogen price, the LCOM values for the base case scenarios are analyzed. This analysis aims to identify the hydrogen price in the Netherlands that would result in an LCOM equivalent to that observed in the base case scenarios. By examining these LCOM values of the base case, the hydrogen price can be identified as needed to achieve cost parity with the identified scenarios. The hydrogen price is evaluated in a range from 0 €/kg to 10 €/kg, the result is graphically shown in Figure 4.23.

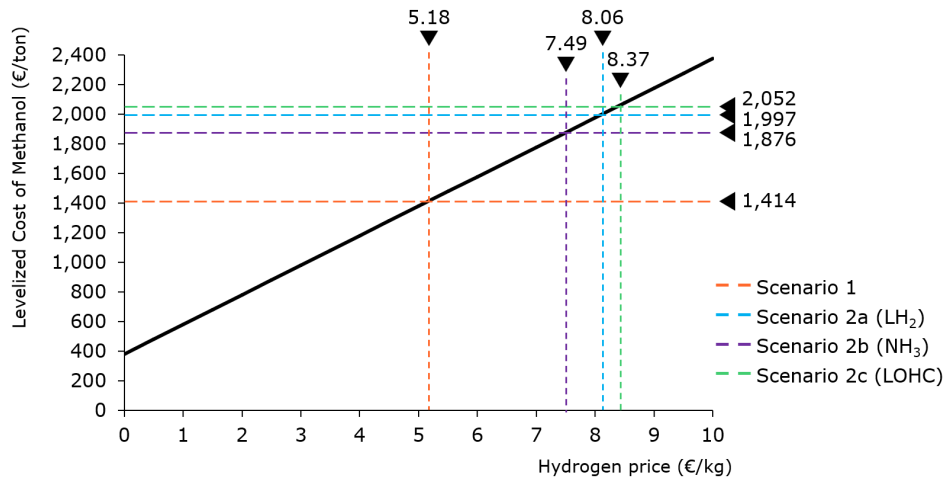


Figure 4.23: Comparison of LCOM values in the Netherlands using locally sourced feedstocks at varying hydrogen prices with base case scenarios. The graph illustrates the threshold hydrogen prices at which the LCOM values for local production match those of the respective base case scenarios

The graph in this figure shows the LCOM of the low-case shipping distance plotted against varying hydrogen prices. The solid black line represents the LCOM as a function of the hydrogen price in this local production scenario. The horizontal-colored dashed lines indicate the LCOM values for the four different scenarios in the base case. The corresponding vertical dashed lines intersecting the solid black line represent the hydrogen prices in the Netherlands at which the LCOM of local production would match the LCOM of each base case scenario. Specifically, these intersections signify the threshold hydrogen prices required for cost parity between locally produced methanol and methanol produced under each of the four base case scenarios.

For the LCOM of methanol production in the Netherlands to be equivalent to Scenario 1, where methanol is produced with CO₂ exported to Saudi Arabia and imported back, the hydrogen price must be 5.2 €/kg. This suggests that local methanol production would be cost-competitive if hydrogen can be sourced at or below this price. To match Scenario 2a, involving liquid hydrogen import from Saudi Arabia, the hydrogen price must be 8.0 €/kg, reflecting the higher costs of importing and converting liquid hydrogen.

For Scenario 2b, which imports hydrogen as ammonia, the hydrogen price must be 7.5 €/kg. This indicates relative cost-efficiency, making domestic production favorable if prices are at or below this level. To achieve cost parity with Scenario 2c, involving LOHC-based hydrogen import, the hydrogen price must be 8.4 €/kg. This is the highest threshold, indicating significant costs, thus requiring highly competitive local production to be economically viable.

This analysis suggests that if hydrogen can be produced at or below a price of 5.2 €/kg, domestic methanol production using locally sourced feedstocks would be economically advantageous compared to all the scenarios evaluated in this study. If the price of hydrogen in the Netherlands exceeds 8.4 €/kg, all the scenarios examined in this study would offer better economic advantages compared to domestic methanol production with locally sourced feedstocks.

These values are in line with the research from (Burchardt et al. 2023), which indicates the anticipated green hydrogen production costs in Europe. Initially, it was expected to be below 3 €/kg, but this has proven unrealistic due to elevated energy market prices and structural challenges in renewable project supply chains. Consequently, the current hydrogen project suggests that production will range from 5

€/kg to 8 €/kg by 2030 in Europe.

As defined in Section 3.3.2, the hydrogen price for the low-case is set at 8 €/kg, resulting in an LCOM of 1.98 €/kg MeOH. This Scenario would be economically competitive with Scenario 2a and Scenario 2b. For Scenario 2a, the cost parity indicates that domestic production using locally sourced feedstocks would be advantageous over the liquid hydrogen import option, due to the absence of complex logistics and infrastructure requirements. In the case of Scenario 2c, while the LCOM values are relatively close, importing LOHC remains more favorable than the domestic option. However, the minimal deviation in LCOM suggests that the advantages of simpler logistics and reduced infrastructure demands make the domestic option a viable alternative.

Hydrogen sourced from Chile

In the high case, the LCOM for the different scenarios is recalculated with a shipping distance of 14,000 km between Chile and the Netherlands. The prices for raw materials and utilities remain consistent with the base case scenario, as the renewable energy conditions in Chile are assumed to be equivalent to those in Saudi Arabia. The resulted LCOM values of the scenarios are shown in Figure 4.24.

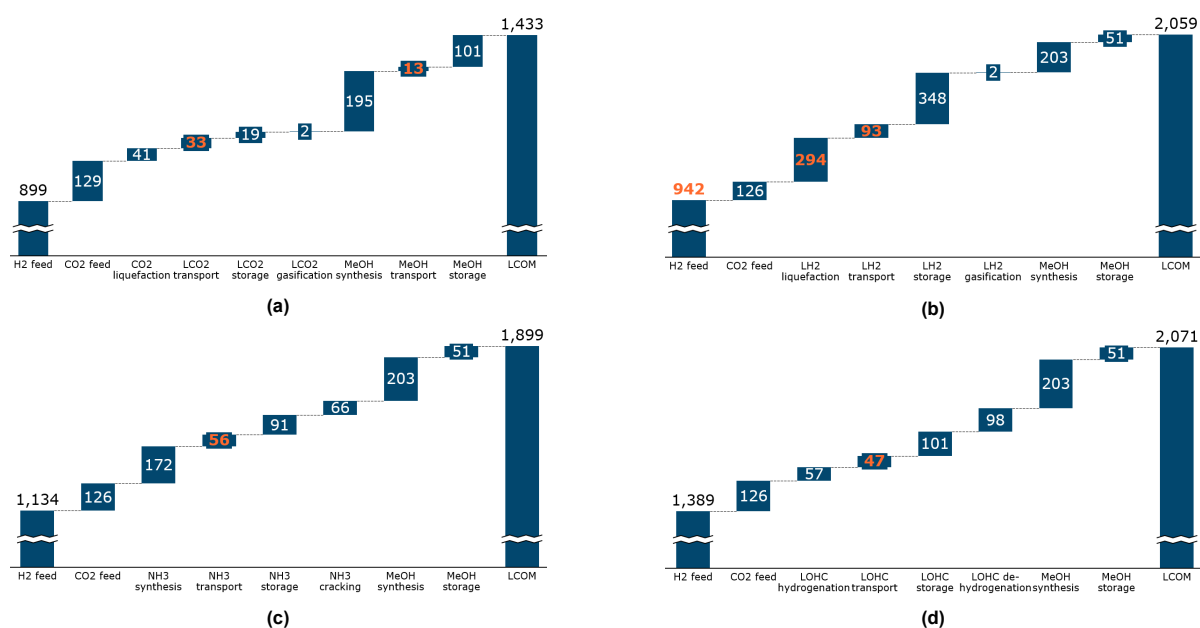


Figure 4.24: Sensitivity analysis results on the LCOM with a shipping distance of 14,000 km for (a) Scenario 1, (b) Scenario 2a (LH₂), (c) Scenario 2b (NH₃), and (d) Scenario 2c (LOHC)

This figure presents four waterfall diagrams illustrating the updated LCOM. The orange numbers within the diagrams indicate the specific components whose values have changed due to the modified shipping distance. When shipping the considered chemicals in the different scenarios, the total LCOM equals 1.43 €/kg for Scenario 1, 2.06 €/kg for Scenario 2a, 1.90 €/kg for Scenario 2b, and 2.07 €/kg for Scenario 2c.

An anticipated outcome is that the shipping costs in each scenario will differ after adjusting the shipping distance. In every scenario, the shipping component is approximately 1.7 times bigger than in the base case. A more notable thing is the variation in the hydrogen liquefaction and hydrogen feed in Scenario 2a. This higher LCOM is due to the increased boil-off that logically occurs with longer shipping distances and longer travel times. A higher boil-off rate necessitates more feedstock and that increases the costs of the liquefaction process, as a larger quantity of hydrogen needs to be liquefied.

Although there are changes in the total LCOM, the ranking of the different Scenarios stays the same when considering a shipping distance of 14,000 km. Scenario 1 is still the most cost-effective option, followed by Scenario 2b, Scenario 2a, and Scenario 2c, respectively.

4.3.4. Methanol capacity

This Subsection explains the outcomes of the sensitivity analysis by varying the annual methanol production capacity. In the base case, the annual production of methanol is 200 kt per year. The low and the high cases for this sensitivity analysis are 90 kt/yr and 310 kt/yr, respectively.

The outcomes for the defined cases are shown in Table 4.18. To visualize the behavior of the LCOM by varying the methanol capacity, all values in a range from 90 to 320 kt/yr are plotted in a graph in Figure 4.25. The corresponding exact values can be found in Appendix C, Figure C.3.

Case	Scenario 1	Scenario 2a (LH ₂)	Scenario 2b (NH ₃)	Scenario 2c (LOHC)
90 kt/yr	1,635	2,604	2,148	2,198
200 kt/yr	1,414	1,997	1,876	2,052
310 kt/yr	1,340	1,803	1,790	1,999

Table 4.18: Results of the sensitivity analysis for the methanol capacity, LCOM in [€/ton MeOH]

The graph in Figure 4.25 illustrates the sensitivity of the methanol capacity on the LCOM across the different scenarios. When the methanol production capacity increases, the LCOM gradually decreases. This behavior arises due to the application of a scaling factor of 0.6 in the CAPEX calculation. Consequently, the curve of the LCOM will not be linear. A scaling factor less than 1 indicates the presence of economies of scale, where the total costs decrease at a slower rate than the production capacity increases.

The graph reveals one critical intersection point, which indicates a shift in the ranking of the scenarios. From a methanol capacity of 175 kt/yr, Scenario 2c (with LOHC import) becomes more expensive than Scenario 2a (with LH₂ import). This shift suggests that importing liquid hydrogen becomes more cost-effective when the methanol capacity increases.

The graph also indicates that another intersection point will occur between Scenario 2a (LH₂ import) and Scenario 2b (NH₃ import) when the methanol capacity increases further, out of the range of the graph. This shift suggests that importing liquid hydrogen becomes even more cost-effective when the methanol capacity increases even further.

Throughout the range of production capacities considered, Scenario 1 consistently remains the most cost-effective option, with the lowest LCOM across the range.

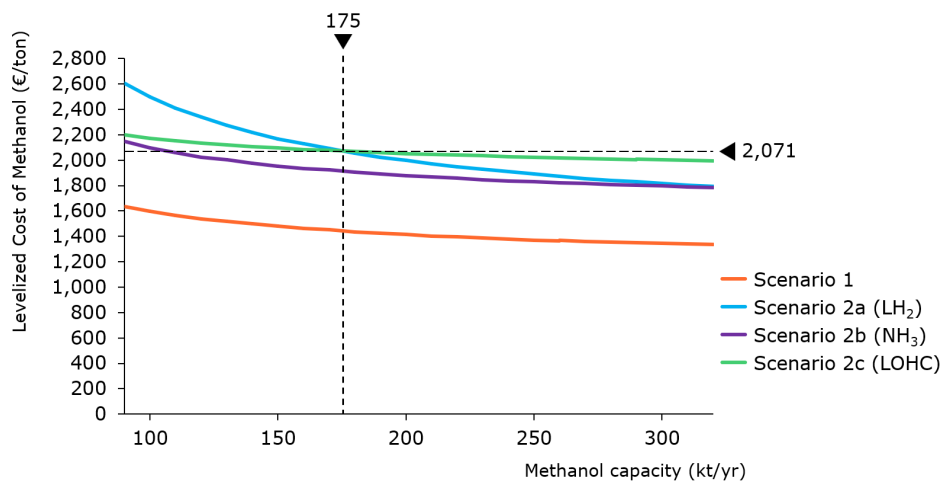


Figure 4.25: Methanol capacity sensitivity analysis results in graph

5

Conclusions and recommendations

This Chapter starts with answering the research sub-questions as well as the main research question to formulate the conclusions to this study, provided in Section 5.1. The conclusions are followed by Section 5.2, which elaborates on recommendations that are provided for future research, based on gained insights from the discussion of the results and the conclusion.

5.1. Conclusion

In this study, the optimal E-methanol value chain was analyzed through a comparative assessment of two distinct supply scenarios, evaluated from both technical and economic perspectives. The first strategy considered involves the export of captured CO₂ from the Netherlands to Saudi Arabia, with subsequent E-methanol synthesis, which is shipped back to the Netherlands for further use and distribution. The second strategy considers the import of hydrogen from Saudi Arabia in the form of three different carriers, which breaks this scenario down into three scenarios, with local E-methanol synthesis in the Netherlands.

The analysis was conducted under the boundary conditions that the value chain ensures methanol availability within the Netherlands, that CO₂ is captured in the Netherlands, and that the hydrogen required for E-methanol production is sourced from Saudi Arabia. A techno-economic analysis was conducted on four different scenarios, resulting in a calculated LCOM for each scenario.

To find the optimal E-methanol value chain, a main research question with three sub-research questions is formulated. Section 5.1.1 gives answers to the sub-research questions and Section 5.1.2 answers the main research question of this study.

5.1.1. Sub-research questions

This Subsection provides answers to the three sub-research questions which are presented below.

1. *What are the main cost drivers in different scenarios of the value chain to get E-methanol in the Netherlands using hydrogen from Saudi Arabia?*

Since this sub-question asks for the main cost drivers per scenario, the question is answered for each Scenario separately. The main cost drivers are identified by their contribution to the total LCOM. The remaining components considered in the value chains have a minimal impact on the total LCOM values when compared to the main cost drivers, and therefore not mentioned in this Section.

In **Scenario 1**, where CO₂ is exported to Saudi Arabia for local E-methanol production which is imported back to the Netherlands, the total LCOM in the base case equals 1.4 €/kg. The highest contributor to this value is the hydrogen feed with an LCOM of 0.9 €/kg. This high contribution highlights the substantial impact of hydrogen production on the overall cost. Following the hydrogen feed, the E-methanol synthesis unit has the second highest contribution with an LCOM of 195

€/ton. This reflects the cost-intensive nature of the synthesis process, which involves significant energy and operational inputs. Subsequently, the CO₂ feed contributes 129 €/ton highlighting the high cost associated with capturing. Lastly, the E-methanol storage facility adds 101 €/ton to the total LCOM, indicating the importance of storage infrastructure in the value chain.

In **Scenario 2a**, where green hydrogen is imported as liquid hydrogen from Saudi Arabia for E-methanol production in the Netherlands, the total LCOM in the base case equals 2.0 €/kg. With an LCOM of 0.9 €/kg, the hydrogen feed is also in this scenario the highest contributor to the LCOM, but with a lower relative contribution. Following the hydrogen feed in this scenario, the second most significant cost driver is the liquid hydrogen storage facility, with an LCOM of 348 €/ton. This indicates that the infrastructure and operational costs for storing liquid hydrogen are substantial due to the specialized equipment and conditions required for the storage of hydrogen in the liquid state. The same accounts for the conversion from gaseous hydrogen to liquid by liquefaction, this LCOM is 290 €/ton. The energy-intensive nature of converting hydrogen from gas to liquid accounts for this significant cost contribution. Also in this scenario, the E-methanol synthesis unit is one of the main cost drivers with a contribution of 203 €/ton.

In **Scenario 2b**, where green hydrogen is imported via the hydrogen carrier ammonia from Saudi Arabia for E-methanol production in the Netherlands, the total LCOM in the base case equals 1.9 €/kg. The hydrogen feed has an even higher contribution in this scenario, compared to the previous ones, of 1.1 €/kg. The second largest cost driver is the E-methanol synthesis unit, contributing an LCOM of 203 €/ton. Following closely to the E-methanol synthesis is the ammonia synthesis unit, with an LCOM of 172 €/ton. The process of converting hydrogen into ammonia involves relatively high costs, which highlights the energy needs of this process. The remaining components in this scenario have a substantially smaller component compared to the main cost drivers but have a relatively larger contribution than the remaining components in the other scenarios. This indicates that the deviation between the different components is smaller in this scenario.

In **Scenario 2c**, where green hydrogen is imported via the LOHC dibenzyltoluene from Saudi Arabia for E-methanol production in the Netherlands, the total LCOM in the base case equals 2.1 €/kg. The hydrogen feed in this scenario has the largest LCOM among the scenarios, as well as the largest relative contribution of 66% with an LCOM of 1.4 €/kg. Also in this scenario, the E-methanol synthesis unit is the second largest cost driver, contributing 203 €/ton to the total LCOM. The third largest cost driver is the CO₂ feed with an LCOM of 126 €/ton, and the fourth largest cost driver is the storage of the LOHC with an LCOM of 101 €/ton. Also in this scenario, the remaining components have a relatively small LCOM deviation compared to the largest cost drivers.

2. *What is the most economically feasible way to import hydrogen from Saudi Arabia to the Netherlands for E-methanol production?*

To answer this question, only the different variants of Scenario 2 are considered because in this scenario hydrogen is imported from Saudi Arabia to the Netherlands in the form of liquid hydrogen, via ammonia or chemically bound to the LOHC dibenzyltoluene. Scenario 1 is excluded as it does not involve hydrogen carrier import.

In each scenario, the hydrogen feedstock is the primary cost driver which gives high priority to an economically friendly option for this substance. The LCOH for the import of the three different carriers in the base case is calculated and this resulted in an LCOH of 8.1 €/kg when importing hydrogen in liquid form, an LCOH of 7.5 €/kg when importing hydrogen as ammonia, and an LCOH of 8.4 €/kg when importing hydrogen as LOHC.

This analysis reveals that Scenario 2b, involving the import of hydrogen as ammonia, is the most economically feasible option in the base case considered in this study. This scenario requires more hydrogen than Scenario 2a, but the infrastructure components have a lower LCOH compared to this scenario. When comparing the import of ammonia to the import of the LOHC in Scenario 2c, the LCOH of the hydrogen feed is higher in the LOHC scenario, but the infrastructure components have a lower LCOH.

From an infrastructure perspective, the scenario involving LOHC emerges as the most economically feasible option, followed by the scenarios involving ammonia and liquid hydrogen, respectively. When evaluating the required amount of hydrogen feedstock, the liquid hydrogen scenario is the most efficient, requiring the least amount of hydrogen, followed by the ammonia and LOHC scenarios. Both infrastructure feasibility and hydrogen feed requirements are critical factors in determining the optimal hydrogen import strategy. Consequently, considering these aspects, importing hydrogen in the form of ammonia from Saudi Arabia to the Netherlands presents itself as the most viable option.

The sensitivity analysis reveals different outcomes for the most economically feasible hydrogen carrier based on variations in parameter values. If the hydrogen price in Saudi Arabia fluctuates, the relative economic feasibility of the carriers also shifts. When the price decreases below 4.0 €/kg, ammonia remains the best option, however, importing liquid hydrogen becomes more expensive than importing LOHC. If the hydrogen price decreases further below 1.4 €/kg, the LOHC import option becomes more cost-effective than the import of ammonia. Conversely, if the price increases to 7.1 €/kg or higher, importing liquid hydrogen becomes the most economically viable option.

Furthermore, the methanol capacity influences the economic feasibility of the different hydrogen carriers. If the E-methanol production capacity within the value chain decreases below 155 kt/yr, importing liquid hydrogen becomes more economically feasible than using LOHC, although ammonia remains the best option. It is anticipated that with further increases in E-methanol production capacity beyond that examined in this study, importing liquid hydrogen would also become more cost-effective than ammonia. In this case, LOHC remains the least economically feasible option.

To conclude, in the base case, the best option for hydrogen import from Saudi Arabia to the Netherlands is via the hydrogen carrier ammonia. If hydrogen prices in Saudi Arabia increase above 7 €/kg or if the E-methanol production capacity of the synthesis unit expands to be higher than 320 kt/yr, liquid hydrogen becomes the most economically feasible option. If the hydrogen price drops below 1.4 €/kg, the case of importing LOHC becomes the most effective option for hydrogen import.

3. *What are optimization opportunities for the value chain of E-methanol?*

To enhance the economic and operational efficiency of the E-methanol value chain, several optimization opportunities can be considered. Two optimization opportunities are covered in this answer to this sub-question.

Storage facilities represent a significant cost component in the value chain, and the design of the storage tanks is related to the sizes of the vessels used for shipping. One optimization point lies in balancing the vessel size related to the storage capacity. The size of the vessel directly influences the frequency of roundtrips required for transportation between Saudi Arabia and the Netherlands. Larger vessels can reduce the number of roundtrips, thereby decreasing the charter transportation costs. However, this approach necessitates larger and thus more expensive storage facilities to accommodate the increased volume per shipment. Conversely, using smaller vessels increases the number of roundtrips, which may raise the transportation costs, but reduce the storage capacity and the associated costs.

Conducting a detailed analysis of the trade-offs between shipping costs and storage infrastructure expenses to determine the optimal vessel and storage size can identify an economically optimal point between these components. This approach offers a viable option for optimizing the E-methanol value chain.

Although transportation costs are not part of the main cost drivers, they contribute to significant components of the infrastructure in the chain and contribute to emissions. From a technical and infrastructural perspective, the value chain would be optimized if the shipping components were eliminated. However, this 'efficient' option entails substantially higher costs compared to the most favorable scenario in the base case. An optimization strategy from a geographical

perspective involves identifying a region closer to the Netherlands than Saudi Arabia that has similar renewable energy potential.

For instance, while Saudi Arabia benefits from abundant solar energy, alternative regions with considerable hydropower resources may also supply sufficient renewable energy. Also, countries like Spain and Portugal are well-positioned to produce green hydrogen because of their renewable energy potential. The shorter shipping distances from these countries to the Netherlands not only lower transportation costs but also reduce the environmental impact associated with long-distance shipping.

5.1.2. Main research question

This Subsection provides an answer to the main research question which is presented below.

Which E-methanol value chain scenario is the most technical and economically effective for ensuring E-methanol availability in the Netherlands, based on a comparative analysis of distinct supply strategies using hydrogen sourced from Saudi Arabia?

In this study, the optimal E-methanol value chain for ensuring methanol availability in the Netherlands was analyzed from both a technical and economic perspective. Two primary configurations of the value chain were considered. The first configuration involves the export of captured CO₂ from the Netherlands to Saudi Arabia, where E-methanol is produced using locally sourced hydrogen, this E-methanol is then transported back to the Netherlands. The second configuration considers the import of hydrogen via a hydrogen carrier from Saudi Arabia to the Netherlands, with subsequent E-methanol production domestically in the Netherlands.

Scenario 1, which includes exporting captured CO₂ to Saudi Arabia and then importing the produced E-methanol back to the Netherlands, consistently demonstrates economic viability and resilience across various sensitivity analyses. Despite the different intuitive feelings, the scenario that involves two shipping stages emerges as the optimal choice from both technical and economic perspectives within this study.

The sensitivity analysis demonstrates variability in the ranking of scenarios for cost-effectiveness when certain parameters are adjusted. However, Scenario 1 consistently emerges as the most economically viable option across the various sensitivity tests. This indicates that Scenario 1 has a lower sensitivity to parameter fluctuations compared to other scenarios. Specifically, its economic viability is less affected by changes in key factors such as hydrogen price, shipping distance, and methanol production capacity.

In conclusion, from both technical and economic viewpoints, the optimal E-methanol value chain for ensuring methanol availability in the Netherlands involves capturing CO₂ domestically, producing E-methanol in Saudi Arabia using locally sourced hydrogen, and transporting the produced E-methanol back to the Netherlands. This consistent performance of this configuration underscores the resilience and reliability of this scenario as the preferred configuration for E-methanol production, even under varying conditions.

5.2. Recommendations

Recognizing the assumptions and boundary conditions that were applied to this study, this Section aims to provide potential further research directions to give more certainty and reliability to the E-methanol value chain analysis.

Firstly, the comparative analysis conducted in this study is necessarily high-level. A more detailed examination of the individual components within the value chain could provide deeper insights into the specific factors that significantly influence the overall cost and efficiency. By delving deeper into the technical and economic aspects of each component, it becomes easier to identify areas with significant optimization potential. For example, areas that could be deepened from a technical point of view could be the specifications of components used in the considered plants to see which components are the most energy-intensive. From an economic point of view, the CAPEX and OPEX values could be analyzed in more detail by summing up all the separate contributors to those expenditures. This detailed

analysis would allow for a clearer understanding of which factors are major cost drivers and which have a minor impact, thereby enabling more targeted and effective optimization strategies.

Secondly, another recommendation is to expand the scope of the research by including the feedstock production processes. Particularly for hydrogen production, which is the largest cost driver in each scenario, incorporating a comprehensive analysis of its production process can provide valuable insights. For instance, having a broad understanding of the reason why these prices remain high and examining the hydrogen production process in greater detail could reveal specific inefficiencies or opportunities for cost reduction. Including feedstock production in the research scope will not only enhance the understanding of the cost dynamics but also provide a more holistic view of the value chain.

Thirdly, incorporating a Life Cycle Analysis (LCA) could add valuable environmental aspects and potential impacts to the outcomes of this study. LCA is a systematic method used to assess the environmental impacts associated with all stages of a product's life cycle, from raw material extraction to disposal or recycling. Integrating LCA into this Techno-Economic Analysis (TEA), it ensures that not only the technical and economic impacts are considered, but also the environmental impacts across the entire value chain. This comprehensive approach significantly enhances the certainty and reliability of the study, providing a holistic evaluation of the sustainability of the E-methanol production process.

Finally, exploring alternative renewable energy sources and production locations closer to the Netherlands could further optimize the value chain. By investigating the potential of sourcing hydrogen from regions with nearly similar renewable energy potentials, such as Spain or Portugal, the study could identify opportunities to reduce transportation costs and associated emissions. These regions have substantial solar and wind resources, which could be used for green hydrogen production, potentially offering a more cost-effective and environmentally friendly alternative to hydrogen from Saudi Arabia. Additionally, identifying countries with high potential in other renewable energies, such as hydropower or geothermal energy, could further enhance the economic feasibility of the E-methanol supply chain.

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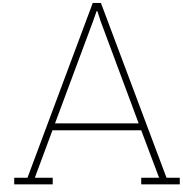
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CEPCI Index Values

This Appendix presents the Chemical Engineering Plant Cost Index (CEPCI) values used for the inflation calculation, presented in Table A.1.

The CEPCI provides a standardized method for adjusting historical costs to current values, ensuring consistency across different projects and time periods. This standardization is vital for comparing costs accurately and making informed financial decisions.

To apply the CEPCI for inflation adjustment, equation A.1 is used. This equation multiplies historical cost data by the ratio of the CEPCI value for the current year to the CEPCI value for the historical year. This adjustment ensures that the cost estimates are current and reflective of present-day economic conditions (Whitesides 2012).

$$C_B = C_A \cdot \frac{CEPCI_{year,B}}{CEPCI_{year,A}} \quad (A.1)$$

Year	CEPCI value
2024 (Feb)	800.3
2023	798.0
2022	816.0
2021	708.8
2020	596.2
2019	607.5
2018	603.1
2017	567.5
2016	541.7
2015	556.8
2014	576.1
2013	567.3
2012	584.6
2011	585.7
2010	550.8
2009	521.9
2008	575.4
2007	525.4
2006	499.6
2005	468.2
2004	444.2

Table A.1: CEPCI index values 2004 - 2024 (Skills 2024)

B

Accuracy Analysis Results

B.1. Base case

Figure B illustrates the impact of accuracy margins applied to the CAPEX and OPEX values on the LCOM for the different scenarios in the base case. The analysis considers a $\pm 50\%$ accuracy margin for CAPEX values and a $\pm 10\%$ for the OPEX values of the components within the value chains.

For each scenario, the blue bars represent the LCOM when a + 50% accuracy margin for CAPEX and a + 10% accuracy margin for OPEX values are applied, indicating the upper bound of the LCOM. Conversely, the orange bars indicate the LCOM when - 50% and - 10% accuracy margins are applied, representing the lower bound of the LCOM per scenario. The values at the top and bottom of these bars denote the maximum and minimum LCOM values, respectively.

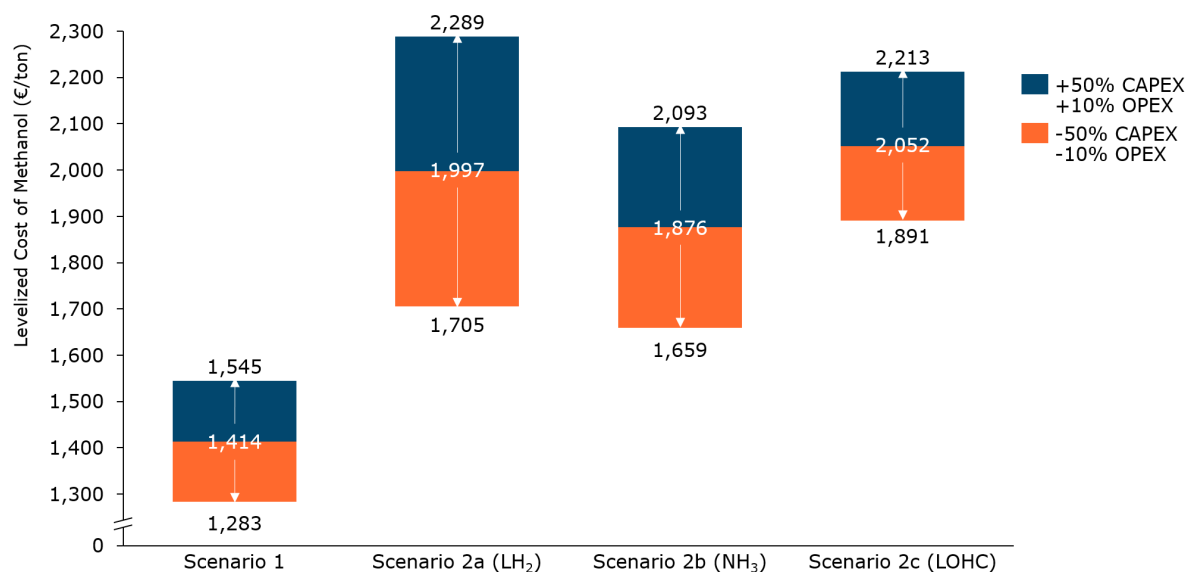


Figure B.1: Results of the applied accuracy margins for CAPEX and OPEX by an accuracy analysis for the LCOM in the base case

In Scenario 1, the LCOM ranges from 1.3 €/kg to 1.5 €/kg, demonstrating relatively modest sensitivity to the applied accuracy margins. Scenario 2a shows a broader range, with the LCOM varying between 1.7 €/kg and 2.3 €/kg, indicating higher sensitivity, particularly due to the substantial CAPEX associated with hydrogen storage and liquefaction infrastructure. Scenario 2b, with a range from 1.7 €/kg to 2.1 €/kg, and Scenario 2c, ranging from 1.9 €/kg to 2.2 €/kg, further illustrate the impact of these variations.

When examining the ranking of the scenarios based on the upper and lower accuracy limits, it is evident that Scenario 1 consistently remains the most economically viable option. Even at the upper limit of 1,545 €/ton, Scenario 1 is still more cost-effective than the lower limits of Scenarios 2a, 2b, and 2c.

For the different hydrogen import scenarios, a shift in the ranking is seen at the upper limit of the accuracy ranges. When the accuracy margin of + 50% CAPEX and + 10% OPEX are applied, the liquid hydrogen import becomes the least cost-effective option. This shows a difference compared to the base case, where the import of LOHC is the least cost-effective scenario.

Furthermore, this accuracy analysis reveals the dependency of each scenario on CAPEX and OPEX. Scenario 2a exhibits the highest dependency on CAPEX and OPEX, as indicated by the significant range between the upper and lower LCOM values. This high sensitivity is primarily due to the substantial infrastructure costs associated with hydrogen storage and liquefaction.



Sensitivity Analysis

This Appendix presents the detailed results of the sensitivity analysis conducted in this study. The sensitivity analysis evaluates how variations in key input parameters impact the LCOM across the different scenarios.

Table C.1 presents the detailed outcomes resulting from the variation in the hydrogen feedstock price. Table C.2 illustrates the results of varying the CO₂ feedstock price, and Table C.3 shows the outcomes of the sensitivity analysis related to the methanol production capacity.

For each scenario, the tables list the LCOM values corresponding to the variations in the respective parameter. To provide a clear comparison of economic feasibility, a color scale has been applied to the values within each table. Values shaded in green indicate higher economic feasibility, reflecting lower LCOM values.

C.1. Hydrogen feedstock price

Table C.1 shows the LCOM values for different production capacities across four the four scenarios.

Scenario 1 shows LCOM values in a range from 715 €/ton at an hydrogen price of 1.00€/kg to 2,512 €/ton at 10.00€/kg. This scenario is highly sensitive to hydrogen prices, with significant increases in LCOM values as hydrogen prices rise.

Scenario 2a starts at 1,280 €/ton at 1.00€/kg, the LCOM value increases to 3,125 €/ton at 10.00€/kg. This scenario shows extreme sensitivity to hydrogen prices, making it the least economically feasible at higher H₂ prices.

Scenario 2b shows the LCOM values in a range from 995 €/ton at 1.00€/kg to 3,262 €/ton at 10.00€/kg. This scenario also shows high sensitivity to hydrogen prices, with substantial cost increases.

Scenario 2c shows the LCOM values in a range from 972 €/ton at 1.00€/kg to 3,749 €/ton at 10.00€/kg. This scenario is the most sensitive to hydrogen price variations, with the highest increase in LCOM values among all scenarios.

H ₂ price (€/kg)	Scenario 1	Scenario 2a (LH ₂)	Scenario 2b (NH ₃)	Scenario 2c (LOHC)	
€ 1.00	€ 715	€ 1,280	€ 995	€ 972	
€ 1.50	€ 815	€ 1,382	€ 1,121	€ 1,126	
€ 2.00	€ 915	€ 1,485	€ 1,246	€ 1,281	
€ 2.50	€ 1,015	€ 1,587	€ 1,372	€ 1,435	
€ 3.00	€ 1,114	€ 1,690	€ 1,498	€ 1,589	
€ 3.50	€ 1,214	€ 1,792	€ 1,624	€ 1,744	
€ 4.00	€ 1,314	€ 1,895	€ 1,750	€ 1,898	
€ 4.50	€ 1,414	€ 1,997	€ 1,876	€ 2,052	base case
€ 5.00	€ 1,514	€ 2,100	€ 2,002	€ 2,206	
€ 5.50	€ 1,614	€ 2,202	€ 2,128	€ 2,361	
€ 6.00	€ 1,714	€ 2,305	€ 2,254	€ 2,515	
€ 6.50	€ 1,813	€ 2,407	€ 2,380	€ 2,669	
€ 7.00	€ 1,913	€ 2,510	€ 2,506	€ 2,824	
€ 7.50	€ 2,013	€ 2,612	€ 2,632	€ 2,978	
€ 8.00	€ 2,113	€ 2,715	€ 2,758	€ 3,132	
€ 8.50	€ 2,213	€ 2,817	€ 2,884	€ 3,286	
€ 9.00	€ 2,313	€ 2,920	€ 3,010	€ 3,441	
€ 9.50	€ 2,412	€ 3,022	€ 3,136	€ 3,595	
€ 10.00	€ 2,512	€ 3,125	€ 3,262	€ 3,749	

Figure C.1: Sensitivity analysis results of the LCOM when varying the hydrogen price with color-coded outcome [€/ton MeOH]

C.2. CO₂ feedstock price

Table C.2 shows the LCOM values for different production capacities across four the four scenarios.

Scenario 1 shows the LCOM values in a range from 1,300 €/ton at a CO₂ price of 10€/ton to 1,521 €/ton at 155€/ton. This scenario shows moderate sensitivity to CO₂ price changes, maintaining relatively low LCOM values.

Scenario 2a shows that the LCOM values in this scenario range from 1,886 €/ton at 10€/ton to 2,101 €/ton at 155€/ton. The increase in CO₂ prices significantly impacts the economic feasibility, making this scenario less attractive.

Scenario 2b starts at 1,765 €/ton at 10€/ton, the LCOM value increases to 1,973 €/ton at 155€/ton. This scenario shows a moderate increase in costs with rising CO₂ prices, maintaining a competitive position.

Scenario 2c shows that the LCOM values range from 1,941 €/ton at 10€/ton to 2,156 €/ton at 155€/ton. The scenario demonstrates higher sensitivity to CO₂ prices, resulting in a significant increase in LCOM values.

CO ₂ price (€/ton)	Scenario 1	Scenario 2a (LH ₂)	Scenario 2b (NH ₃)	Scenario 2c (LOHC)
€ 10.00	€ 1,300	€ 1,886	€ 1,765	€ 1,941
€ 15.00	€ 1,307	€ 1,893	€ 1,772	€ 1,948
€ 20.00	€ 1,315	€ 1,901	€ 1,780	€ 1,956
€ 25.00	€ 1,323	€ 1,908	€ 1,787	€ 1,963
€ 30.00	€ 1,330	€ 1,916	€ 1,794	€ 1,970
€ 35.00	€ 1,338	€ 1,923	€ 1,802	€ 1,978
€ 40.00	€ 1,345	€ 1,930	€ 1,809	€ 1,985
€ 45.00	€ 1,353	€ 1,938	€ 1,817	€ 1,993
€ 50.00	€ 1,361	€ 1,945	€ 1,824	€ 2,000
€ 55.00	€ 1,368	€ 1,953	€ 1,832	€ 2,008
€ 60.00	€ 1,376	€ 1,960	€ 1,839	€ 2,015
€ 65.00	€ 1,384	€ 1,968	€ 1,847	€ 2,022
€ 70.00	€ 1,391	€ 1,975	€ 1,854	€ 2,030
€ 75.00	€ 1,399	€ 1,982	€ 1,861	€ 2,037
€ 80.00	€ 1,406	€ 1,990	€ 1,869	€ 2,045
€ 85.00	€ 1,414	€ 1,997	€ 1,876	€ 2,052
€ 90.00	€ 1,422	€ 2,005	€ 1,884	€ 2,060
€ 95.00	€ 1,429	€ 2,012	€ 1,891	€ 2,067
€ 100.00	€ 1,437	€ 2,020	€ 1,899	€ 2,074
€ 105.00	€ 1,444	€ 2,027	€ 1,906	€ 2,082
€ 110.00	€ 1,452	€ 2,034	€ 1,913	€ 2,089
€ 115.00	€ 1,460	€ 2,042	€ 1,921	€ 2,097
€ 120.00	€ 1,467	€ 2,049	€ 1,928	€ 2,104
€ 125.00	€ 1,475	€ 2,057	€ 1,936	€ 2,112
€ 130.00	€ 1,483	€ 2,064	€ 1,943	€ 2,119
€ 135.00	€ 1,490	€ 2,072	€ 1,951	€ 2,126
€ 140.00	€ 1,498	€ 2,079	€ 1,958	€ 2,134
€ 145.00	€ 1,505	€ 2,087	€ 1,965	€ 2,141
€ 150.00	€ 1,513	€ 2,094	€ 1,973	€ 2,149
€ 155.00	€ 1,521	€ 2,101	€ 1,980	€ 2,156

base case

Figure C.2: Sensitivity analysis results of the LCOM when varying the CO₂ price with color-coded outcome [€/ton MeOH]

C.3. Methanol capacity

Table C.3 shows the LCOM values for different production capacities across four the four scenarios.

Scenario 1 consistently demonstrates the lowest LCOM values across all capacities, indicating high economic feasibility. As the production capacity increases from 90 ky/yr to 320 kt/yr, the LCOM values decrease from 1,635 to 1,335 €/ton, reflecting the benefits of economies of scale.

Scenario 2a starts with the highest LCOM value of 2,604 €/ton at 90 kt/yr, which decreases to 1,792 €/ton at 320 kt/yr. Despite the reduction, it remains less economically feasible compared to the other scenarios due to the high costs associated with liquid hydrogen.

Scenario 2b shows a range from 2,148 €/ton at 90 kt/yr to 1,783 €/ton at 320 kt/yr for the LCOM. The trend shows a significant decrease in costs with increasing capacity, making it more competitive at higher capacities.

Scenario 2c starts at 2,198 €/ton at 90 kt/yr, the LCOM value drops to 1,995 €/ton at 320 kt/yr. Although this scenario benefits from economies of scale, it remains less economically feasible compared to Scenario 1 and Scenario 2b.

Capacity (kt/yr)	Scenario 1	Scenario 2a (LH ₂)	Scenario 2b (NH ₃)	Scenario 2c (LOHC)	
90.00	€ 1,635	€ 2,604	€ 2,148	€ 2,198	
100.00	€ 1,599	€ 2,498	€ 2,099	€ 2,172	
110.00	€ 1,564	€ 2,411	€ 2,058	€ 2,152	
120.00	€ 1,539	€ 2,338	€ 2,023	€ 2,136	
130.00	€ 1,520	€ 2,275	€ 2,004	€ 2,120	
140.00	€ 1,498	€ 2,216	€ 1,977	€ 2,108	
150.00	€ 1,481	€ 2,169	€ 1,954	€ 2,096	
160.00	€ 1,464	€ 2,128	€ 1,933	€ 2,085	
170.00	€ 1,451	€ 2,091	€ 1,923	€ 2,076	
180.00	€ 1,436	€ 2,054	€ 1,906	€ 2,067	
190.00	€ 1,426	€ 2,024	€ 1,890	€ 2,059	
200.00	€ 1,414	€ 1,997	€ 1,876	€ 2,052	base case
210.00	€ 1,403	€ 1,973	€ 1,870	€ 2,045	
220.00	€ 1,395	€ 1,947	€ 1,858	€ 2,039	
230.00	€ 1,386	€ 1,927	€ 1,847	€ 2,034	
240.00	€ 1,379	€ 1,908	€ 1,836	€ 2,028	
250.00	€ 1,371	€ 1,890	€ 1,832	€ 2,023	
260.00	€ 1,369	€ 1,874	€ 1,823	€ 2,019	
270.00	€ 1,361	€ 1,856	€ 1,815	€ 2,014	
280.00	€ 1,355	€ 1,842	€ 1,807	€ 2,010	
290.00	€ 1,350	€ 1,829	€ 1,804	€ 2,006	
300.00	€ 1,344	€ 1,817	€ 1,797	€ 2,002	
310.00	€ 1,340	€ 1,803	€ 1,790	€ 1,999	
320.00	€ 1,335	€ 1,792	€ 1,783	€ 1,995	

Figure C.3: Sensitivity analysis results of the LCOM when varying the methanol capacity with color-coded outcome [€/ton MeOH]