Large-scale hydrogen supply chain: A comprehensive evaluation

vorgelegt von
M. Sc.

Jimena Incer Valverde

ORCID: 0000-0003-3611-3325

an der Fakultät III - Prozesswissenschaften
der Technischen Universität Berlin
zur Erlangung des akademischen Grades

Doktor der Ingenieurwissenschaften
- Dr.-Ing. -

genehmigte Dissertation

Promotionsausschuss:

Vorsitzender: Prof. Dr. Boris Heinz
Gutachterin: Prof. Dr. Tetyana Morozyuk
Gutachter: Prof. Dr. Sergio Mussati
Gutachter: Prof. Dr.-Ing. George Tsatsaronis

Tag der wissenschaftlichen Aussprache: 21. Juli 2023

Berlin 2023

Acknowledgement

First, I want to thank my supervisor, Prof. Morozyuk, with whom I spent many hours discussing interesting topics and challenges related to the hydrogen economy. Without her support and trust in me, I could not have finished this thesis with five published papers and on time, according to my future plans. Thank you for constantly pushing me to give my best and attend several conferences, where I gained invaluable experience. I am grateful for the opportunity to conduct this research as part of the Energy Engineering Department, part in Egypt, at the TU Berlin Campus El Gouna and most of the time at the main Campus in Berlin.

I also want to thank Prof. Tsatsaronis for his mentorship, productive discussions, and exchange of views. Also, for improving our papers with his assertive comments. I am thankful for his time and guidance since the very beginning of my PhD.

To my former and current colleagues, Sarah, Sara, Bahaa, Louay, Jing, Nico, and Olga, with whom I had a great time in Egypt and enriching academic discussions. I would especially like to thank Sarah for her mentorship and help to publish our first paper. I would also like to express my gratitude to the rest of my El Gouna colleagues and the administration department, including Christina, Krystina, Claudia, and Ina. Also, to the KT WiMis who crossed my path in Egypt and Berlin, especially to Elisa, Sebastian and Stefan.

I want to thank the students I taught over these years and the master's students I supervised during this time, who made me gain the overall picture of the hydrogen economy very quickly. I would like to especially acknowledge those remarkable students who became coauthors of four of the papers that helped finalize this thesis on time. To Janis, the first student I supervised, who set the bar very high for the rest. To Laura, my friend and master's student, who did an excellent job. Also, to Olaniyi, now a colleague, I wish him great success in his PhD. To Claudia, who helped with all the possible changes to find better hydrogen regasification configurations. Finally, to Amira and Ying, whose papers are under review and hopefully will be published soon.

I also want to thank Felipe, my future husband, for his support, trust in me, and for helping me balance my priorities. Also, for many enriching academic discussions.

Thanks to my friends for their support, motivation and helping me balance my life. To Irene and Mónica from Costa Rica, who I always felt close despite the distance. Also, to my friends in Berlin, who became like family to me, Marce, Caro, Hanna, Anna, Bianca, Abi and Lau.

A lot of what I have accomplished in my life is thanks to my parents, Blanca Rosa and Augusto. They have been my pillars of unconditional support and motivation. To my siblings, Laura, Diego, Gabi, and my aunt Esther, who have motivated me as well. Also, to my lovely niece, Leonor, since she was born, I want to become a better role model for her.

Finally, I would like to acknowledge the support provided by the Universidad de Costa Rica and the reserved position to work at the University once I am back in Costa Rica. I am looking forward to transferring all the knowledge I can to my future students back home.

Abstract

The current climate change crisis requires extraordinary efforts to reduce the overall carbon dioxide emissions. One of the solutions to this problem is the transition of dependency from fossil fuels to renewable energy sources, such as solar, and wind. This shift to a more environmentally friendly alternative comes with many challenges. A key and suitable solution to store fluctuating renewable energy power must be established. Hydrogen is a promising energy carrier for storing and distributing renewable energy around the world.

This thesis provides a comprehensive analysis of the large-scale hydrogen economy. It extensively evaluates the entire process of green liquid hydrogen, including gas and liquid hydrogen production, as well as the reconversion to hydrogen gas via the regasification of liquid hydrogen. The study includes energetic, exergetic, and economic analyses.

For green hydrogen production, a PEM electrolyzer is considered, and an exergy efficiency of 60% is calculated, and the levelized cost of green hydrogen amounts to 8.8 US$/$kg_{H2}$. For the liquefaction of hydrogen, the exergetic efficiency is determined to be 42%, and the levelized cost of liquid hydrogen corresponds to 1.7 US$/$kg_{H2.}$ For hydrogen regasification, the exergy efficiency is found to be 62%. A levelized cost for hydrogen regasification is calculated at 0.7 US$/$kg_{H2}$. Additionally, the costs are determined based on different operating hours and electricity prices. For the values above, 7446 h/a and 110 US$/MWh were considered, respectively. Even though large-scale hydrogen regasification presents challenges due to the cryogenic temperature of liquid hydrogen (-252.8 °C), it also offers the potential to use the transferred exergy during the regasification process, which would otherwise be destroyed.

Hydrogen is the smallest element in the periodic table, and it presents many challenges in its pure form due to its reactivity. Therefore, four pathways for hydrogen transportation and storage are compared with multi criteria decision making tools, namely Power-to-Liquid hydrogen, Power-to-Ammonia, Power-to-Methanol, and Power-to-Hydrogen Gas. The document assesses the current state of the art, properties, challenges, recent developments, and political developments of these Power-to-X options. Relevant parameters for the comparison are selected, and six decision matrices are applied to the case study, Germany.

Among the four technologies considered, Power-to-Ammonia is the best solution for the German scenario, closely followed by Power-to-Methanol, and Power-to-Liquid hydrogen in the last place. The implementation of new policies and regulations, as part of the German hydrogen strategy, is expected to drive down the costs of the entire hydrogen chain in the future. It is important to mention that all the Power-to-X options are technically feasible, and with the right political support, carbon pricing, and increased demand, Power-to-X technology has the potential to become economically viable.

Keywords: hydrogen economy, liquid hydrogen chain, Power-to-X, regasification of liquid hydrogen, multi criteria evaluation

Zusammenfassung

Die Klimakrise erfordert außerordentliche Anstrengungen zur Verringerung der gesamten Kohlendioxidemissionen. Eine der Lösungen für dieses Problem ist die Umstellung der Abhängigkeit von fossilen Brennstoffen auf erneuerbare Energiequellen wie Solar- und Windenergie. Diese Umstellung ist mit vielen Herausforderungen verbunden. Es muss eine wichtige und geeignete Lösung für die Speicherung der schwankenden Energie aus erneuerbaren Quellen gefunden werden. Wasserstoff ist ein vielversprechender Energieträger für die Speicherung und Verteilung von erneuerbaren Energien auf der Welt.

Die vorliegende Arbeit liefert eine umfassende Analyse der großtechnischen Wasserstoffwirtschaft. Sie bewertet ausführlich den gesamten Prozess des grünen Flüssigwasserstoffs, einschließlich der Produktion von gasförmigem und flüssigem Wasserstoff sowie der Rückumwandlung in Wasserstoffgas über die Regasifizierung von flüssigem Wasserstoff. Die Studie umfasst exergetische und ökonomische Analysen.

Für die Erzeugung von grünem Wasserstoff wird ein PEM-Elektrolyseur betrachtet und ein Exergie-Wirkungsgrad von 60 % errechnet, wobei sich die nivellierten Kosten für grünen Wasserstoff auf 8,8 US$/$kg_{H2}$ belaufen. Für die Verflüssigung von Wasserstoff wird ein exergetischer Wirkungsgrad von 42,1 % ermittelt, und die nivellierten Kosten für flüssigen Wasserstoff entsprechen 1,7 US$/$kg_{H2}$. Für die Wiedervergasung von Wasserstoff wird ein exergetischer Wirkungsgrad von 62 % ermittelt. Die spezifischen nivellierten Kosten für die Wasserstoffverflüssigung werden mit 0,7 US$/$kg_{H2}$ berechnet. Zusätzlich werden die Kosten auf der Grundlage verschiedener Betriebsstunden und Strompreise ermittelt. Obwohl die Regasifizierung von Wasserstoff in großem Maßstab aufgrund der kryogenen Temperatur des flüssigen Wasserstoffs (-252,8 °C) eine Herausforderung darstellt, bietet sie auch das Potenzial, die während des Regasifizierungsprozesses übertragene Exergie zu nutzen, die ansonsten verschwendet würde.

Wasserstoff ist das kleinste Element und stellt in seiner pur Form aufgrund seiner Reaktivität viele Herausforderungen dar. Daher werden vier Wege für den Transport und die Speicherung von Wasserstoff mit Hilfe von multikriteriellen Entscheidungshilfen verglichen, nämlich Power-to-Liquid-Wasserstoff, Power-to-Ammonia, Power-to-Methanol und Power-to-Hydrogen Gas. In dem Dokument werden der aktuelle Stand der Technik, die Eigenschaften, und die politischen Entwicklungen dieser Power-to-X-Optionen bewertet. Es werden relevante Parameter für den Vergleich ausgewählt und sechs Entscheidungsmatrizen auf die Fallstudie Deutschland angewendet. Unter den vier betrachteten Technologien ist Power-to-Ammonia die beste Lösung für das deutsche Szenario, dicht gefolgt von Power-to-Methanol. Es wird erwartet, dass die Umsetzung neuer politischer Maßnahmen und Vorschriften im Rahmen der deutschen Wasserstoffstrategie die Kosten der gesamten Wasserstoffkette in Zukunft senken wird.

Stichworte: Wasserstoffwirtschaft, Flüssigwasserstoffkette, Power-to-X, Regasifizierung von flüssigem Wasserstoff, Multikriterienbewertung

Contents

Nomenclature

A	performance value, -
a	area, m^2
$AFUDC$	allowance for funds used during construction, US$
$ANCF$	average net cash flow, US$
ARR	average rate of return, %
$A.W.S.V$	average weighted sum value ratio, -
BMC	bare module cost, US$
CC	carrying charges, US$
$CELF$	constant escalation levelization factor, -
$CEPCI$	chemical engineering cost index, -
$C.I.$	consistency index, -
$C.R.$	consistency ratio, -
CRF	capital recovery factor, -
DC	direct cost, US$
e	specific exergy, kW/kg
$\dot{E}$	exergy rate, W
f	factor, -
FC	fuel cost, US$
FCI	fixed capital investment, US$
h	specific enthalpy, kJ/kg
HHV	higher heating value, MJ/kg
i	average cost of money, -
IC	indirect cost, US$
IRR	internal rate of return, %
k	constant value, -
LCO	levelized cost, US$
LHV	lower heating value, MJ/kg
$\dot{m}$	mass flow rate, kg/s
n	plant economic life, year
OMC	operation and maintenance costs, US$
NPV	net present value, US$
p	pressure, bar
P	performance score, -
PB	payback period, US$
PEC	purchased equipment cost, US$
Q	preference score, -
$\dot{Q}$	heat duty, W
r	constant escalation rate, -
$R.I.$	random index, -
S	Euclidean distance from the ideal value, -
SEU	specific energy use, kWh/kg
T	temperature, K
TCI	total capital investment, US$
TRR	total revenue requirement, US$

U	overall heat transfer coefficient, W/m^{2}K
V	ideal value, -
w	weighting factor, -
$\dot{W}$	power, W
x	normalized value, -
x	characteristic value, -
Y	net cash flows, US$
y	ratio, -

Greek symbols

α	scaling factor
ε	exergetic efficiency, %
η	isentropic efficiency, %
Δ	difference, -
λ	rate of WSM and WPM, -
τ	payback years

Subscripts

0	environmental conditions
BM	bare module
D	destruction
d	design
eff	effective
F	fuel
FC	fuel costs
i	refers to a stream
j	refers to a column
k	refers to a component
L	losses
L	liquid state
Lev	levelized
ln	natural logarithmic
m	material
min	minimum
OMC	operation and maintenance costs
P	product
p	pressure
T	temperature
tot	total
z	specific year

Superscripts

$+$	best
$-$	worst
Ch	chemical

m	total criteria
M	mechanical
n	lifetime
Ph	physical
Th	thermal

Abbreviations

AHP	analytic hierarchy process
AWE	alkaline water electrolysis
BoP	balance of the plant
CAES	compressed air energy storage
CAPEX	capital expenditure
CCS	carbon capture and storage
CCUS	carbon capture utilization and storage
$\mathrm{CGT-R}$	closed cycle gas turbine with recuperator
COP	conference of the parties
EES	engineering equation solver
ESS	energy storage system
FC&HJU	Fuel Cells and Hydrogen Joint Undertaking
g	gaseous
GBP	British pound sterling
HC	Hydrogen Council
HE	Hydrogen Europe
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
LAES	liquid air energy storage
LCA	life cycle assessment
LH_2	liquid hydrogen
LNG	liquefied natural gas
LOHC	liquid organic hydrogen carriers
MACRS	modified accelerated cost recovery system
MCDM	multi criteria decision making
MENA	Middle East and North Africa
NG	natural gas
OGT	open gas turbine system
$\mathrm{o-p-conv}$	ortho-para conversion
PEM	polymer electrolyte membrane
PtCH3OH	power-to-methanol
PtGH2	power-to-hydrogen gas
PtH, P2H	power-to-hydrogen gas
PtLH2	power-to-liquid hydrogen
PtNH3	power-to-ammonia
PtX, P2X	power-to-X
PV	photovoltaic
RES	renewable energy sources
SMR	steam reforming of methane

SOEC	solid oxide electrolyzer cell
TDI	total depreciable investment
TOPSIS	technique for order preference by similarity to ideal solution
TPD	ton per day
TRL	technology readiness level
WASPAS	weighted aggregated sum product assessment
WEC	World Energy Council
WPM	weighting product model
WSM	weighting sum model

Component abbreviations

ACM	air compressor
CC	combustion chamber
EXP	expander
HCM	hydrogen compressor
HeCM	helium compressor
HeIC	helium inter-cooler
HeT	helium turbine
HIC	hydrogen inter-cooler
HP	cryogenic hydrogen pump
HT	hydrogen turbine
HX	heat exchanger
REC	recuperator
Regas	regasifier

List of figures

List of tables

Chapter 1. Introduction

The First Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) was completed in 1990 [1]. Climate change is not new, but its effects have quickly worsened in recent years. Political consensus is now on finding mitigation and adaptation measures to address the current climate change crisis.

This decade is decisive in preventing the trespassing of the limit of 1.5 - 2 °C temperature rise according to the pre-industrial levels [2]. One of the required and unavoidable solutions that will be implemented in the following years is the transition of dependency from fossil fuels to renewable energy sources (RES) such as solar, wind, hydro, tidal, geothermal, and biomass energy. This shift from conventional fossil fuels to a more environmentally friendly alternative, with little or no carbon dioxide released into the atmosphere, comes with many challenges. Engineers all over the world are addressing these challenges and finding a solution for this crucial transition.

First, the escalation of energy production from RES everywhere in the world where the conditions permit it should be prioritized. Second, the electrification (with electricity coming from RES sources) of many sectors currently dependent on fossil fuels should be promoted. Third, an alternative energy source for the sectors that cannot electrify should be supported.

The last challenge can be answered with a hydrogen-driven economy, which also helps solve two of the main challenges associated with RES, the fluctuation of energy supply (daily and seasonal) and the unmatched production of energy. Unfortunately, this unmatched energy production sometimes wastes surplus energy when the offer is high, and demand is low.

Even before considering the necessity to find an alternative energy source for high-energy-consumer sectors that are difficult to decarbonize, such as the chemical, cement, and steel industry, there was already a need for storing the energy coming from RES to stabilize its production.

Different energy storage systems (ESS) have been considered for storing surplus and fluctuating RES. For small-scale batteries, alternatives could be used, such as Sodium Sulphur, Vanadium redox flow, Lithium-Ion, or Lead acid battery. Also, Thermal Storage Systems and even Flywheel Storage could be used for low-capacity and low-rated power EES [3]. However, the problem arises for large-scale systems, where primarily geographically dependent technologies are known, such as Pumped Hydro Storage and Compressed Air Energy Storage (CAES). The leading large-scale technologies independent from geographical constraints are Liquid Air Energy Storage (LAES) [4] and Hydrogen Storage.

Hydrogen is a well-studied and versatile energy carrier. It has been proposed as an alternative fuel since the seventies after the first energy crisis. The world has started to discuss hydrogen again, not because of the energy crisis and potential lack of fossil fuels in the future but due to imminent climate change. Hydrogen is so versatile it can be used directly as a fuel for industries such as steel and cement, but it can also be used to store energy or to produce cleaner chemicals [5]. Hydrogen demand today is mainly in the industry (oil refining and steel production) and in the chemical sector (ammonia and methanol production) [6]. In 2020, 45% of the hydrogen produced worldwide was used to synthesize 150 million t of ammonia (NH_3) [7] (70% of the ammonia was consumed to produce fertilizers [8]). The second most synthesized chemical from hydrogen is methanol (CH_3OH), producing 98 million t_{CH3OH}/a [9]. The CH_3OH is used to synthesize formaldehyde, acetic acid, and many plastics.

There are challenges associated with the large-scale production of green hydrogen. First, hydrogen is not a primary fuel but a secondary fuel that needs to be produced from other sources. Also, the small hydrogen molecule is not easy to store and transport over long distances; therefore, different concepts such as Power-to-X (PtX,PtH,P2H or P2X) have been developed during the past years to tackle this problem [10]. The hydrogen economy is expected to work along with a PtX flexible system. Power-to-X ("X" refers to the energy carrier) discusses the utilization of a carbon-free process to produce and store hydrogen. The storage of this fuel can be achieved in liquid or gaseous form, as pure hydrogen, or converted to another energy carrier easier to transport, such as methanol, ammonia, or another liquid organic hydrogen carrier (LOHC)

Today, there is a political pledge to boost the hydrogen economy. More than thirty governments around the globe are committed to scale-up the hydrogen economy and have released either Hydrogen National Plans, Strategies, or Roadmaps. All the climate-related reports of the past recent years present hydrogen as a prominent alternative to reaching net-zero emissions [6], [11] [12], [13], [14], [15].

In the past couple of years, colors have been assigned to hydrogen depending on the process and origin of the energy used to generate it. The hydrogen continues to be colorless, of course, but to understand whether the molecule is produced from RES or not and which process is used to produce it, colors such as green, blue, turquoise, red, grey, black, brown, orange, and yellow have been mentioned [16]. For hydrogen to help solve the climate crisis, this molecule must be produced from RES or nuclear energy through electrolysis process, better known as green and pink hydrogen, respectively. By 2021, more than 94 million t of hydrogen were produced, with 900 million t of CO_2 emissions associated with its production, and only 0.037% came from green hydrogen. Still, this small amount represents an increase of 20% compared to the year before. The global installed capacity of electrolyzers in 2021 was 510 MW [17]. Most of the hydrogen (62%) was produced from steam reforming of methane (SMR), known as grey hydrogen; the rest was mostly from coal and as a byproduct of naphtha production [18].

The global energy supply will most likely continue to increase; therefore, the energy transition to more environmentally friendly solutions must be complemented by efficient emerging technologies available worldwide. PtX offers the versatility that most of the key sectors require to stop depending on fossil fuels. At the same time, PtX enables sector coupling, which is the backbone of the energy transition roadmap to decarbonization in Europe [19]. Finally, PtX aim is the distribution of hydrogen as a new commodity, like oil and natural gas (NG), which allows countries that do not have abundant RES to meet their decarbonization goals. Every country committed to implementing a hydrogen economy will produce part of their hydrogen demand in their country, but many countries, e.g., Germany, will need to import a good portion of green hydrogen from abroad.

PtX technologies are being extensively studied, and every aspect of the production to the delivery chain of the PtX systems is being improved (for each "X – energy carrier"). As any other storage system, PtX as an energy storage alternative consists of a *charging,* a *storage,* and a *discharge* subsystem. The PtX options in this thesis are summarized in Figure 1.1.

- The *charge* corresponds to the "charging" of electricity from RES to produce the green hydrogen via electrolysis process and further liquefaction or production of ammonia (via Haber-Bosch process), methanol (via CO_2 Hydrogenation), or other LOHC.
- The *storage* subsystem consists in storing the produced hydrogen carrier. For the hydrogen economy is especially important to consider storage conditions that allow the transport of the energy carrier over long distances. The energy carrier can be stored as a gas or liquid, even as a solid in some cases, but for large-scale applications, a solid storage is not being considered.
- Finally, the *discharge* part corresponds to the final use of the stored energy. In some cases, the stored chemical might be used directly in industry, but in some cases and sectors, the stored chemical might need to be reconverted to the original hydrogen gas. In these scenarios, different technologies must be considered, e.g., cracking of ammonia, dehydrogenation of methanol, or regasification of hydrogen, if the hydrogen gas was liquefied for its transportation.

After a careful and exhaustive literature review of every aspect of the PtX chain, the main challenges for its large-scale application were identified:

1. Escalation of the RES and electrolysis process worldwide has to be increased.
2. The specific energy use for the liquefaction of hydrogen should decrease. [20].
3. Cracking of ammonia or dehydrogenation plants should be constructed close to import terminals of ammonia or methanol.
4. Hydrogen regasification plants should be built close to the import terminals of liquid hydrogen (LH_2).

The first two challenges address scalation concerns that are possible to solve in an economy-of-scale scenario with adequate incentives from authorities until the technology is profitable. The third challenge is also a matter of the construction of chemical plants to reconvert the energy carrier back to hydrogen (if required). In contrast, the fourth challenge represents a more significant problem since the LH_2 is transported at -252.8 °C, and the amount of energy losses during its regasification is very high, making the process unlikely to be applied in a large-scale scenario with the current small-scale regasification technology. The need for a cogeneration plant to efficiently use the energy released during its regasification is inevitable and would help in making this scenario feasible, like the current liquid natural gas (LNG) transportation chain. During the period where this research was conducted, very few papers were published addressing this challenge or proposing configurations for a cogeneration plant with the regasification of hydrogen and production of energy. Naturally, the regasification of hydrogen can be similar to the LNG regasification. However, LNG is transported at -160 °C and LH_2 at almost 100 °C lower temperature, making the cryogenic process more complex. The evaluation of a cogeneration power plant with two products a) hydrogen gas and b) power, is of great interest and will be explored in this thesis. The identification of the lack of information and little resemblance with the LNG chain gained the attention of the author, and configurations of regasification of liquid hydrogen were evaluated. A configuration was selected, and exergy-based methods were applied to calculate the efficiency of the process and compare it with the known values for LNG.

This thesis consists of six chapters. The state of the art is discussed in Chapter 2; in addition to the literature review about the regasification of hydrogen, this thesis includes an extensive status quo of the current hydrogen-related National Plans and running projects. It also includes the current status of four PtX paths: Power-to-Hydrogen gas (PtGH2), Power-to-Liquid hydrogen (PtLH2), Power-to-Ammonia (PtNH3), and Power-to-Methanol (PtCH3OH). Also, the different colors of hydrogen mentioned in the literature are explained in detail. The systems are discussed in Chapter 3, the charging, storage, and discharge subsystems of each Power-to-X technology are presented. The methodology is discussed in Chapter 4, the exergy-based methods are explained. Also, the selection of the main criteria for comparing the four PtX paths is included, and the multi criteria decision making (MCDM) tools and selected weighting factors for comparison are explained. In Chapter 5, the results of the exergy analysis for the liquid hydrogen chain are shown, and the Power-to-X decision matrices are discussed. The assigned weighting factors to each criterion are examined. The German scenario was considered as a study case since it was clear that the comparison and selection of the best scenario should be a well-analyzed and individual decision for each country. Finally, the conclusions and recommendations are presented in Chapter 6, and the final remarks and outlook of this thesis are summarized in this section.

During the years of research related to this thesis, the following papers were published related to the topics discussed in the next chapters.

1. **Incer-Valverde, J**. Mörsdorf, J. Morosuk, T. Tsatsaronis, G., *Power-to-liquid hydrogen: Exergy-based evaluation of a large-scale system*, (2023) Int. Journal of Hydrogen Energy. Pag 11612-11627. Vol 48. Issue 31. https://doi.org/10.1016/j.ijhydene.2021.09.026.
2. **Incer-Valverde, J**. Patiño-Arévalo, L. Tsatsaronis, G. Morosuk, T. *Hydrogen-driven Power-to-X: State of the art and multicriteria evaluation of a study case*, (2022) Energy Conversion and Management. Pag. 115814. Vol. 266. https://doi.org/10.1016/j.enconman.2022.115814
3. **Incer-Valverde, J**. Korayem, A. Tsatsaronis, G. Morosuk, T. *"Colors" of hydrogen: Definitions and carbon intensity*, (2023) Energy Conversion and Management. Pag. 117294. Vol. 291. https://doi.org/10.1016/j.enconman.2023.117294
4. **Incer-Valverde, J**. Lugo-Mayor, C. Morosuk, T. Tsatsaronis, G. *Evaluation of the Large-scale Hydrogen Supply Chain and Perspectives on LH2 Regasification Cogeneration Systems*, (2023) Journal of Gas Science and Engineering (online). https://doi.org/10.1016/j.jgsce.2023.205005
5. Olaniyi, O. **Incer-Valverde, J**. Morosuk, T. Tsatsaronis, G. *Exergetic and Economic Evaluation of Natural Gas/Hydrogen Blends for Power Generation*, (2023) Journal of Energy Resources Technology. Pag. 1-16. Vol 145. Issue 6. https://doi.org/10.1115/1.4056448

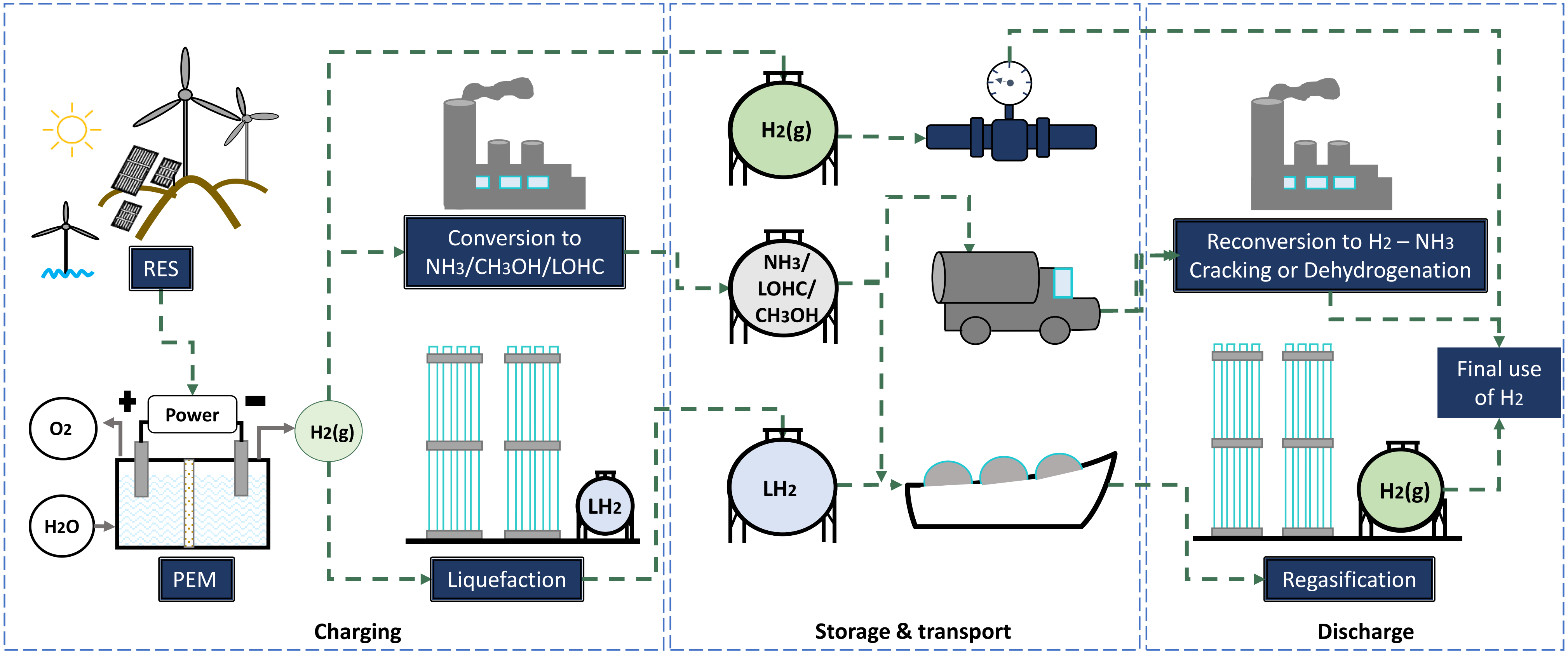


Figure 1.1 Power-to-X storage system with ammonia, methanol, liquid hydrogen, and pure hydrogen gas

Chapter 2. State-of-the-art

The numerous applications and benefits of hydrogen have been studied for many decades. The hydrogen economy presents an opportunity for an abundant, clean, and versatile energy future for the world. The hydrogen economy consists of the hydrogen production, storage, transportation, and conversion of the stored hydrogen.

The worldwide publications found in Scopus Database related to hydrogen since the first paper dated 1862 are shown in Figure 2.1. Three waves are identified; the reasons behind the exploration of hydrogen-related technologies back then were the oil and financial crises [21]. The last wave appeared after the entry into force of the Paris Agreement in 2015 to fight against climate change. In the past years, a significant effort has been invested in deepening hydrogen research as an energy vector and developing the necessary knowledge to generate it as an alternative fuel and storage solution for RES. Of almost 1.5 million research papers related to hydrogen, only ca. 120,000 are energy-related, and almost all were published from 2015 to 2022. After the 21st session of the Conference of the Parties (COP21), the world agreed on the need for a reliable energy alternative to transition to a carbon-free economy. As a result, many nations began to develop strategies to invest in, accelerate and scale up clean hydrogen-related technologies. The main difference between this current hydrogen wave and the past two identified waves is political consensus and commitment. Europe and Japan lead the global hydrogen patenting industry; around half of the patents from 2011-2020 were related to hydrogen production methods. The other half involved hydrogen storage, transportation, and conversion into other energy carriers [21].

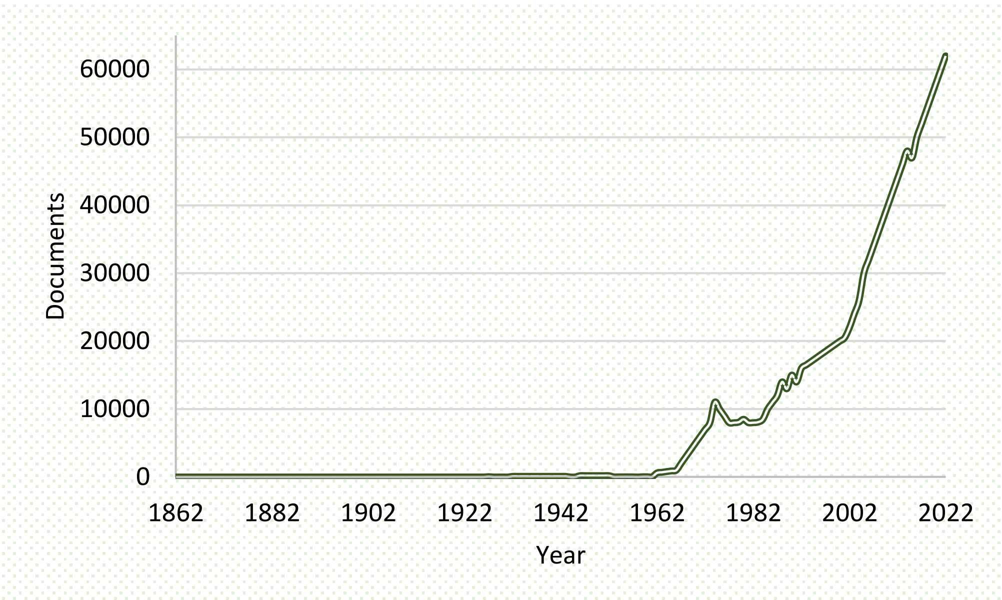


Figure 2.1. Hydrogen-related documents found in Scopus database

By 2021, a global investment of 750 billion US$ was expected to drive the energy transition to clean energy sources. However, experts have concluded that these investments are insufficient to stay below the temperature increase agreed upon at the COP21. [22].

Hydrogen can be a storage solution for fluctuating RES. However, hydrogen is not the only energy transition technology available for energy storage. As mentioned before, there are other well-established large-scale energy storage technologies that do not rely on geographic constraints, for example, liquid air energy storage. An advanced analysis of LAES from an exergetic and economic point of view has been well-studied in [23]. However, many countries agree today that hydrogen will be the energy vector that will make possible the transition to a decarbonized industry [24]. Hydrogen investments, unlike other fuels, are stronger than before the pandemic [22]. In Table 2.1 some relevant thermodynamic properties of hydrogen for the hydrogen economy are summarized.

In recent years, many well-known energy agencies have started to publish reports dedicated exclusively to hydrogen, such as the International Energy Agency (IEA), the International Renewable Energy Agency (IRENA) or the World Energy Council (WEC), and new organizations dedicated exclusively to hydrogen have been founded and provide regular reports, such as the Hydrogen Council (HC), Hydrogen Europe (HE) and Fuel Cells and Hydrogen Joint Undertaking (FC&HJU). Information on the cost of each hydrogen technology and forecasts for the coming years under different scenarios are highly relevant for policymaking, investment, industry, and academia. The number of reports from these sources peaked in 2021, followed by 2022, as shown in Figure 2.2. This does not necessarily mean that the topic has lost relevance compared to 2021, but many factors could have influenced the decrease in the number of reports. For example, many countries planning a National Hydrogen Plan have already implemented it.

Table 2.1. Thermodynamic properties of hydrogen *[25]*, *[26]*, *[27]*

Property	**Value**
Molecular weight (kg/kmol)	2.02
Specific volume (m^3/kg)	12.1
Volumetric H_2 content (kg_{H2}/m^3) compressed at 700 bar	42
Volumetric LH_2 content (kg_{H2}/m^3)	71
Latent heat of evaporation at boiling point (kJ/kg)	447
Liquefaction point (°C) at 1 bar	-252.8
Solidification point (°C) at 1 bar	-259.1
Lower heating value (MJ/kg)	120
Critical temperature (°C)	-240
Lower Heating Value (MJ/kg)	120
Explosion limits in air (%)	4-75

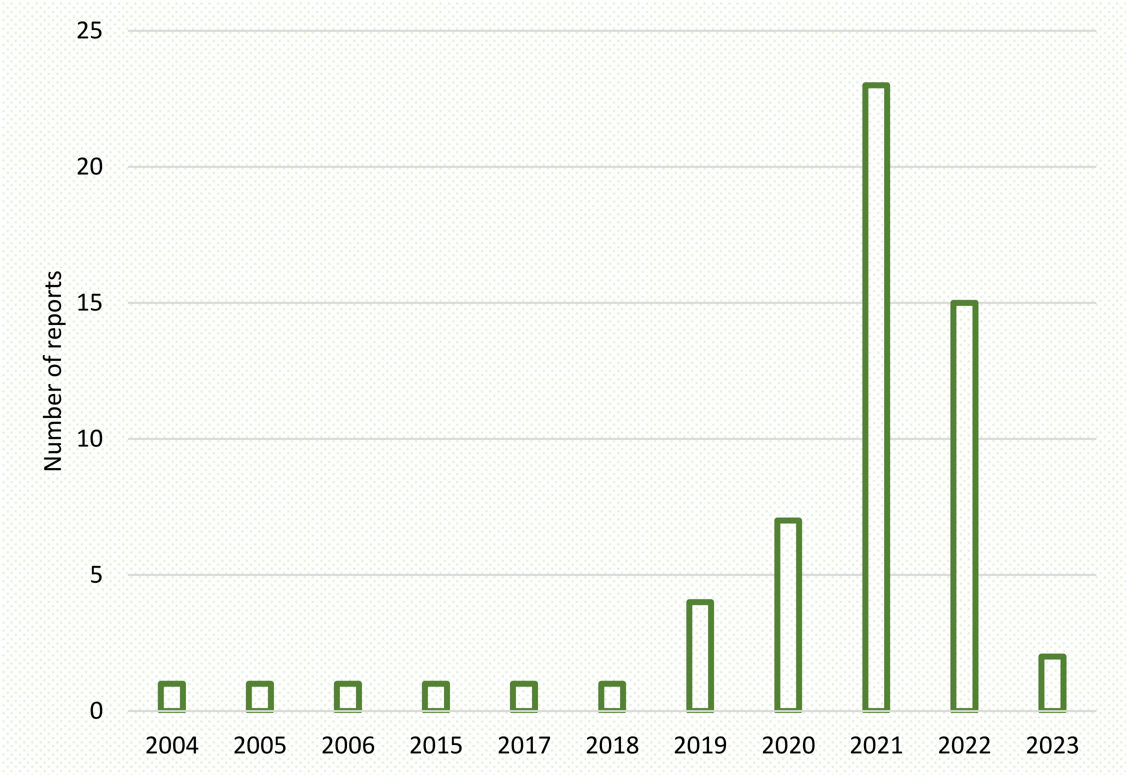


Figure 2.2. Reports dedicated exclusively to hydrogen from IEA, IRENA, WEC, HC, HE, and FC&HJU (until April 2023)

Drawing an analogy with a process integration system, the technologies related to the extensive deployment of a hydrogen economy are no longer in the research and development or conceptual design part but in the detailed engineering scale-up, where investments are often announced. Many partnerships have been established between importing and exporting countries, and detailed pilot plants are already being built or planned. The challenges associated with establishing a hydrogen economy are also directly related to the challenges associated with expanding electricity generation units, mainly from RES [28].

2.1. Hydrogen National Plans

More than thirty nations have launched their Hydrogen National Plan, Strategy, or Roadmap, as presented in Figure 2.3. The year with more plans announced was 2020, followed closely by 2021. The colors mentioned in the strategies and plans of the countries are summarized in Figure 2.4 [29]. This information shows that this hydrogen wave is characterized by the political will to decarbonize many nations.

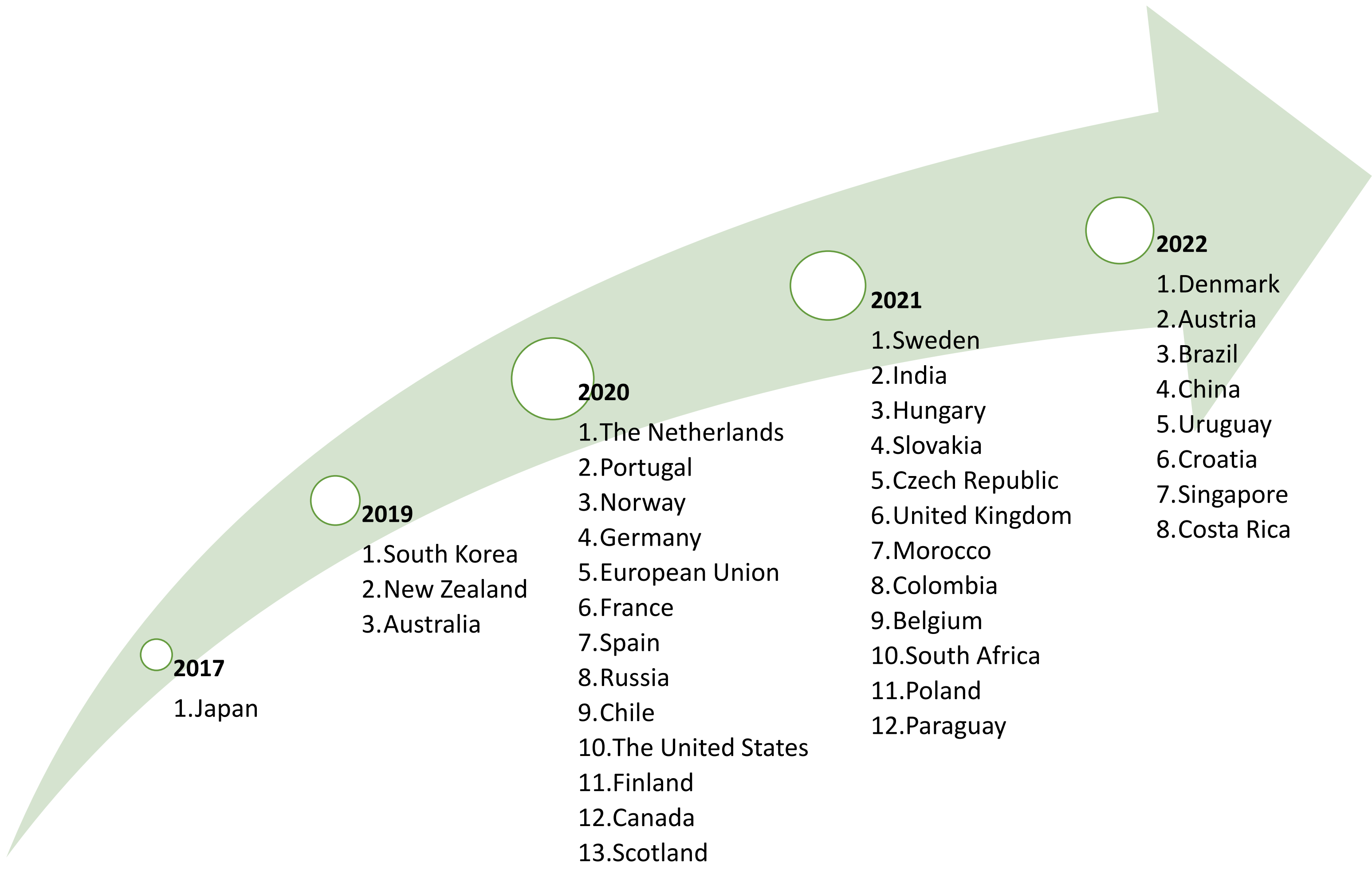


Figure 2.3. Hydrogen National Plans, Strategies, and Roadmaps released by April 2023. (For sources, refer to Table A.1)

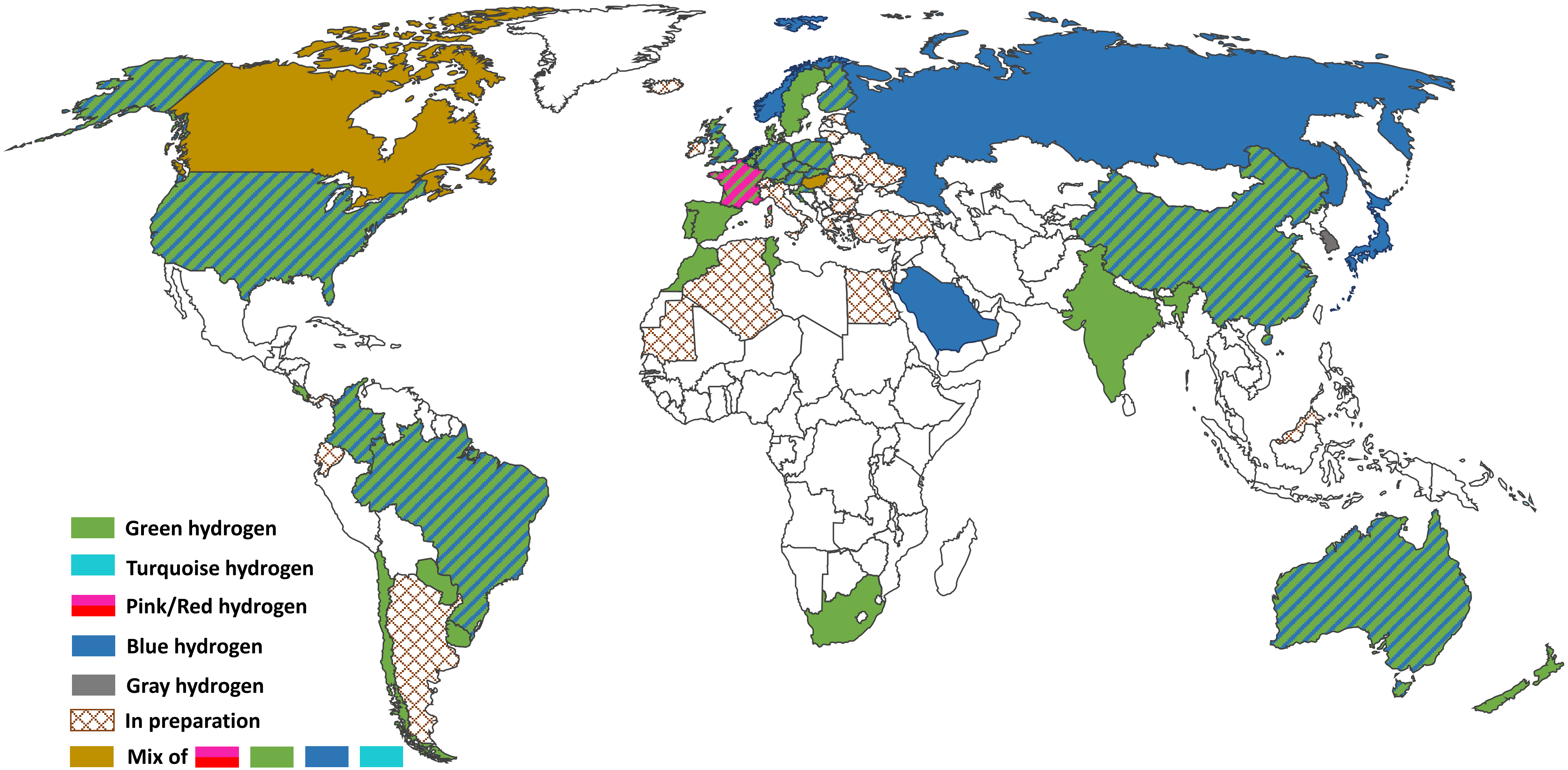


Figure 2.4. Main colors considered in the Hydrogen National Plans, Strategies, or Roadmaps

2.2. "Colors" of hydrogen

At the time of writing, there was no universal naming specification for hydrogen colors. The numerous definitions mentioned in this research differ among the literature, reports, and national plans. This can be confusing, mainly when colors are used interchangeably to indicate the same hydrogen production process. Finding the right keywords related to the hydrogen economy is also challenging. For example, many similar terms are used for green hydrogen, such as low-carbon hydrogen, clean hydrogen, e-hydrogen, clear hydrogen, and many more.

From the reports, documents, press releases, and national plans surveyed, the most common colors mentioned are gray, green, and blue hydrogen [30], [31], [32]; many others also include turquoise [29], [33], [34].

There is a debate about what color should define hydrogen produced from nuclear energy. Some authors assign purple [35], pink [36], or red [37] to general nuclear-powered processes to produce hydrogen. In the summary presented in this section, purple hydrogen is not included, and red and pink have been divided according to the process used to produce hydrogen: thermolysis/thermochemical and electrolysis, respectively. White hydrogen is also subject to confusion. Sometimes white is assigned to naturally occurring hydrogen [38], [39] found, for instance, in caverns. Other sources consider white hydrogen a resultant byproduct of chemical processes [33], which is also not very relevant in a hydrogen economy future scalation since it depends on the need for the main product of the chemical process. However, the hydrogen produced as a byproduct of chemical processes represented 18% of global production in 2021 [18]. Some authors have also mentioned gold hydrogen as the hydrogen produced by fermenting microbes [38]. Finally, there have been different definitions also between orange and yellow hydrogen. Some authors consider yellow the one produced from electrolysis powered by the grid [35], while others use the definition included in this summary, from solar energy via thermolysis/thermochemical processes [40], [41]. The idea to blend green hydrogen with natural gas also gained visibility recently as a way to transition to a 100% hydrogen economy [42].

A set of pathways associated with hydrogen production and associated colors were united as the hydrogen "rainbow" or hydrogen "color wheel" [43]. In the effort to find something from nature (flora or fauna) that includes many relevant colors. A peacock was proposed as a symbol to summarize the various methods of hydrogen production and the ambitions of establishing a global hydrogen economy, as shown in Figure 2.5.

In Table 2.2 the sources of energy, the process for hydrogen production, and the existence of CO_2 emissions for the ten colors shown in Figure 2.5: black, brown, gray, blue, turquoise, green, orange, pink, yellow, and red are presented [44].

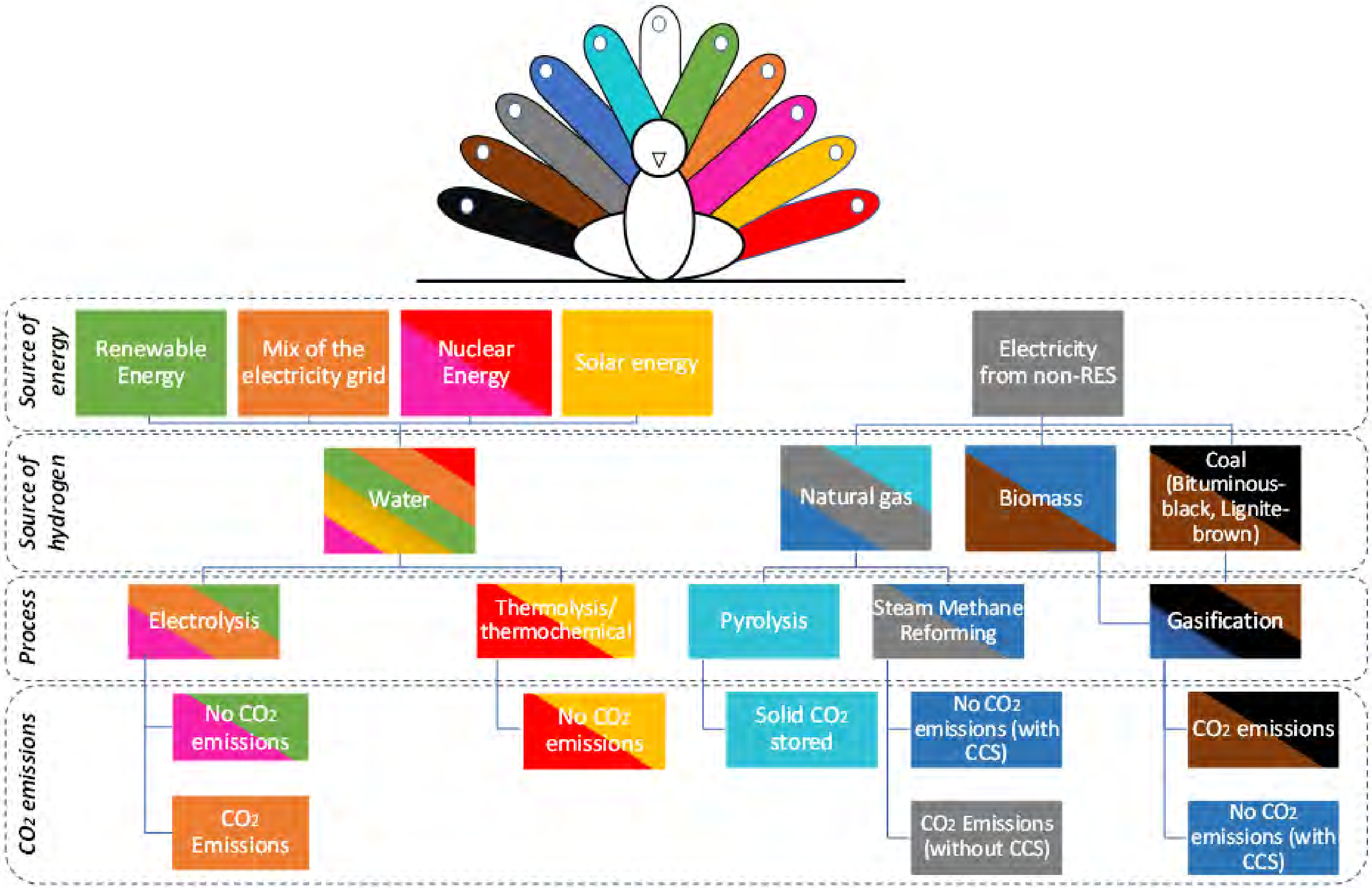


Figure 2.5. Sources of energy and hydrogen, the process of production and the emissions associated with the following colors to refer to hydrogen: green, orange, red, pink, blue, gray, turquoise, brown, black, and yellow *[44]*

According to the clean-energy-transition plan of the EU, hydrogen production methods can be classified as green hydrogen if the electrolyzers operate in countries where over 90% of their electricity is obtained from RES or if the emissions intensity of the electricity falls below a specific threshold [45]. In such scenarios, there won't be a need to introduce additional renewable power capacity into the grid to meet emissions reduction targets. These specific regions already experience surplus renewable electricity generation for extended periods throughout the year, and the production of hydrogen can utilize this excess energy that would otherwise go to waste. However, it is crucial to ensure that hydrogen production occurs during times when renewable electricity is abundantly available. Therefore, the hours designated for hydrogen production are limited to avoid periods of limited and costly renewable electricity supply [46]. Under the EU clean-energy-transition plan, companies utilizing these electricity sources to produce hydrogen can be eligible for financial incentives from the government. However, it is important to note that the green hydrogen label will not be applicable to hydrogen generated through nuclear-powered electrolysis, as clarified by the EU [46]. The most recent IEA report [47], suggests that the international discussions regarding the different hydrogen production methods should be only about the emissions. The report argues this will be the way to move away from using hydrogen colors that can lead to confusion.

Most of the hydrogen today is produced in China (more than 30%) [48]. Green and low-carbon hydrogen are mentioned in their extensive 14th Five-Year Plan [49], and there is now a Medium and Long-Term Plan for Development of the Hydrogen Energy Industry (2021-2035) [50]. The country defined a threshold of 14.5 kg_{CO2}/k_{H2} for “low-carbon” hydrogen (which corresponds to 50% reduction relative to the CO_2 emissions of hydrogen produced from coal gasification in the country). The term “clean and renewable” hydrogen has also been defined when the emissions are lower than 4.9 kg_{CO2}/kg_{H2} (corresponding to a 65% reduction relative to the “low-carbon” hydrogen threshold) [48].

In some reports, the authors try to standardize the definition and reduce the number of terms used to avoid misunderstandings, but this sometimes leads to confusion. For example, the IEA does not use colors to refer to hydrogen; instead of colors, they call renewable hydrogen the one produced by an electrolysis process powered by RES (what many others call green hydrogen) or by biomass-based pathways. Sometimes they use the terms low-emission or low-carbon hydrogen for hydrogen produced by electrolysis when the electricity is generated from a low-emission source (RES or nuclear), biomass, or fossil fuels with carbon capture utilization and storage (CCUS). [18]. In this case, green hydrogen can be renewable hydrogen, low-emission hydrogen, or low-carbon hydrogen, but renewable hydrogen, low-emission hydrogen, or low-carbon hydrogen does not necessarily refer to green hydrogen.

Table 2.2. Definitions of "hydrogen colors"

<table>
<tr><th>Color</th><th>Source of energy</th><th>Source of hydrogen</th><th>Production process</th><th>CO_2 emissions</th></tr>
<tr><td>Green</td><td>Renewable energy</td><td rowspan="5">Water</td><td rowspan="3">Electrolysis</td><td>No direct CO_2 emissions</td></tr>
<tr><td>Orange</td><td>Mix of electricity grid</td><td>Depends on the electricity mix</td></tr>
<tr><td>Pink</td><td rowspan="2">Nuclear</td><td>No direct CO_2 emissions</td></tr>
<tr><td>Red</td><td rowspan="2">Thermolysis/Thermochemical process</td><td>No direct CO_2 emissions</td></tr>
<tr><td>Yellow</td><td>Solar</td><td>No direct CO_2 emissions</td></tr>
<tr><td>Gray</td><td rowspan="5">Electricity from non-renewable energy</td><td>Natural gas</td><td rowspan="2">Steam Methane Reforming</td><td>High</td></tr>
<tr><td>Blue</td><td>Natural gas/Biomass</td><td>Low</td></tr>
<tr><td>Turquoise</td><td>Natural gas</td><td>Pyrolysis</td><td>No direct CO_2 emissions</td></tr>
<tr><td>Brown</td><td>Lignite coal/Biomass</td><td rowspan="2">Gasification</td><td>High</td></tr>
<tr><td>Black</td><td>Bituminous coal</td><td>High</td></tr>
</table>

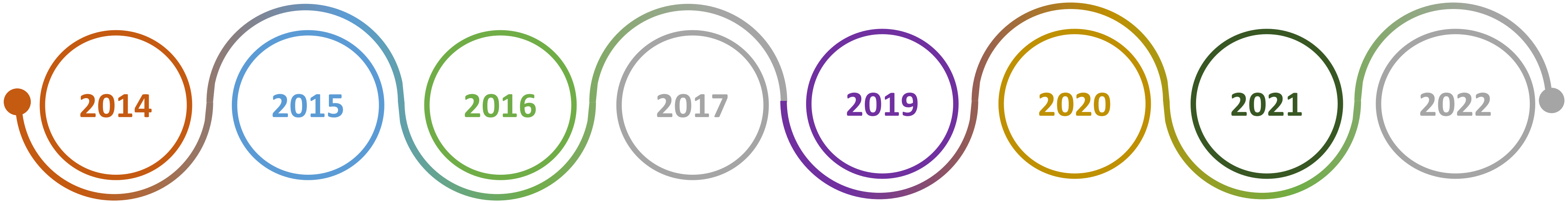
There are other hydrogen production methods not mentioned here, since they are not applicable yet in a large-scale scenario, e.g., photocatalysis, hydrogen produced from biological sources, and solar-driven hydrogen production using biomass as a feedstock [51]. There are also efforts being made to convert plastic waste into clean hydrogen via gasification [52]. Another option reported in the literature is to utilize municipal sludge gasification-based hydrogen production via a plasma gasifier [53]. Finally, direct hydrogen production from the air, namely, the capture of freshwater from the atmosphere using hygroscopic electrolytes and electrolysis powered by solar or wind energy [54].

2.3. Power-to-X

Power-to-X (PtX), or more precisely Power-to-H_2-to-X, is a relatively new concept to integrate hydrogen or other hydrogen energy carriers into a sustainable scenario driven by the electrolysis process. The PtX concept was first published in 2013, with Power-to-Gas being the first alternative to be considered [55]. The definition of the concept has been adjusted in recent years, and since the concept is relatively new, each author has adopted their definition. The term has evolved from Power-to-Gas to Power-to-Liquids and finally to the broader Power-to-X approach, which considers all possibilities of converting electricity into an energy vector such as liquid hydrogen, ammonia, methanol, hydrogen gas, any liquid organic energy carrier or converting electricity into heat. The term has also been expanded to hydrogen-to-industry, hydrogen-to-chemicals, hydrogen-to-long-term energy storage, hydrogen-to-mobility, hydrogen-to-refinery, and hydrogen-to-power, showing the many applications of this energy vector [56].

The main idea behind PtX is to provide a way to store and transport renewable energy, which is inherently intermittent and variable in its generation. By converting the excess electricity into another form, it can be stored and used later when RES are not available or when demand is high. This stability can help to increase the penetration of RES and contribute to a more sustainable energy system.

Selected definitions of "Power-to-X" developed from 2014 to 2022 are presented in Figure 2.6. In Figure 2.7 the selection process of the literature reviewed for this section is shown. From the hydrogen-related publications found in the Scopus database, only 9% are energy-related, and 74% of the energy-related documents were written in the English language. Only papers with the following keywords were selected: hydrogen production, thermodynamics, economics, environmental impact, storage, fuel cell, and the optimization field (group 1). This group still amounts to 34,121 documents. However, only 153 papers are related to Power-to-X (group 2). However, it is essential to mention the difficulty of finding the right keywords related to the hydrogen economy due to its novelty, lack of standardization, and recent development.



"Power-to-X is an option for long-term storage of renewable electricity... as an alternative solution to electricity storage in the hour range as Power-to-X-to-Power." (German Aerospace Center) (translated from German)

" Power-to-Hydrogen (P2H) means pure hydrogen production from Renewable Energy power could also be seen as a sort of power storage as H_2 can be converted back to electricity in fuel cells or by combustion power plants. Synthetic CH_4 from RE could employ the gas distribution systems which has a large storage capacity." (Lund, et al., Finland)

"Power-to-X identifies technologies that transform power from renewable resources into material energy storage, energy carriers, and energy-intensive chemical products. Energy from renewable sources can then be used in the shape of tailor-made fuels for vehicles or in improved plastics and chemical products with greater added value." (Leitner. Germany)

"The “Power-to-hydrogen” (PtH) concept means that once hydrogen is produced from low carbon electricity, a potentially large portfolio of uses is possible. Applications across diverse sectors include transport, blending with natural gas, and electrical power to storage to electrical power." (Dickinson , et al. Australia)

"Power-to-X refers to electrofuels, or e-fuels, which constitute a new concept where hydrogen from electrolysis and CO_2 is converted into liquid fuels." (IRENA)

“Power-to-X describes methods for converting electrical energy into liquid or gaseous chemical energy sources through electrolysis and further synthesis processes. Using electrical current, water is split into oxygen and hydrogen – a 100% CO_2 emission-free process.” (Siemens AG)

"PtX is a blanket term for a number of technologies that are all based on using electricity to produce hydrogen. This hydrogen can subsequently be used directly as a fuel for road transport or industrial purposes or further converted into other fuels, chemicals and materials." (The Denmark´s Government Strategy for Power-to-X)

"Power-to-X is a collective term for conversion technologies that turn electricity into carbon-neutral synthetic fuels, such as hydrogen, synthetic natural gas, liquid fuels, or chemicals. These can be used in sectors that are hard to decarbonise or, unlike electric power, be stored for later use". (Ramboll Group A/S)

Figure 2.6. Selection of Power-to-X concept definitions since the term was adopted *[15]*, *[57]*, *[58]*, *[59]*, *[60]*, *[61]*, *[62]*, *[63]*, *[64]*

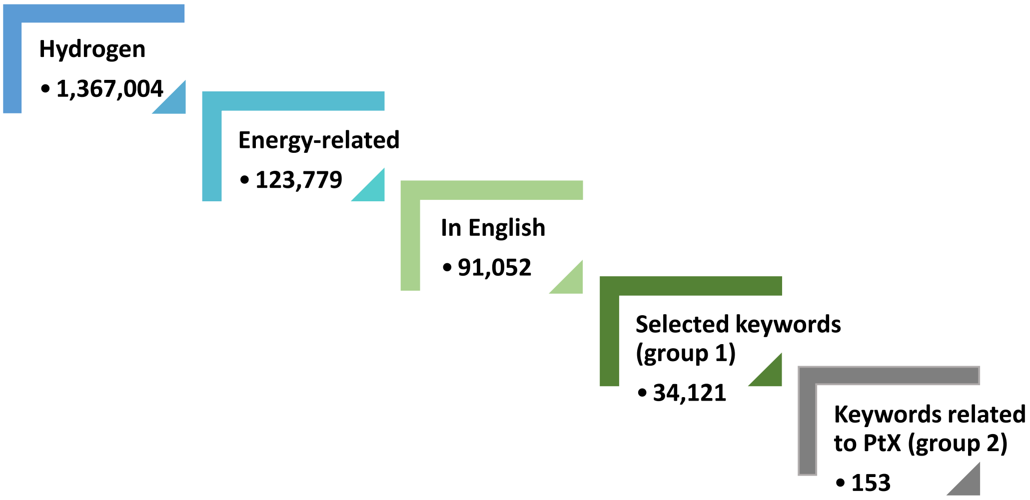


Figure 2.7. The documents selection process for analysis (from Scopus database) *[64]*

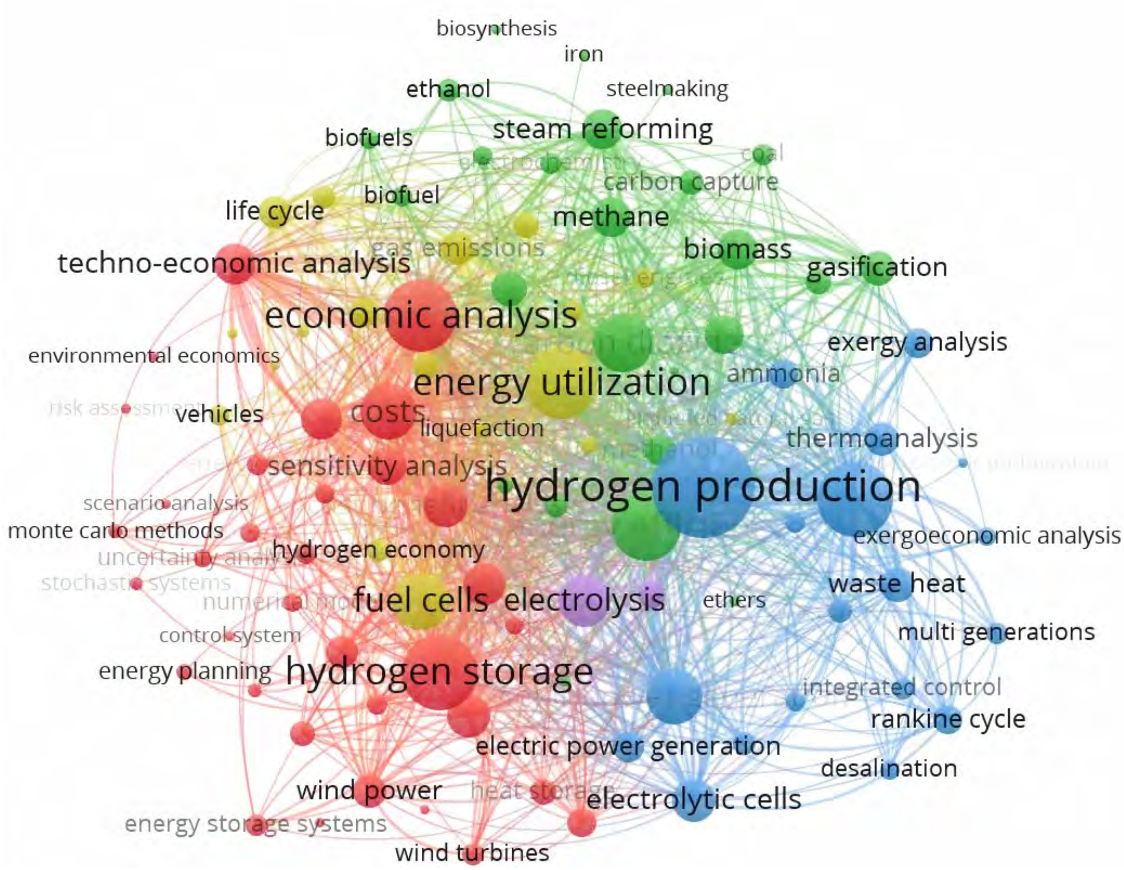


Figure 2.8. Bibliometric map of the interconnection of energy-related hydrogen keywords from VOSViewer software *[64]*

A visual bibliometric analysis of the data collected from the Scopus database was performed using the VOSViewer software 1.6.16 [65]. This software allows the compilation of data to perform complete studies of a bibliometric map. In Figure 2.8 the interconnection between the keywords selected for analysis is shown, as well as the co-occurrence of each topic related to the hydrogen economy in the field of energy.

Finally, the interconnections of the PtX-related keywords are presented in Figure 2.9. One group of keywords has to do with the environmental part of the technology using, for example, life cycle assessment (LCA). The other is with techno-economic analysis and energy scenarios. Finally, the third focuses on the thermodynamics of the storage system. It is possible to conclude that the three main areas are being investigated without any interrelationships between them.

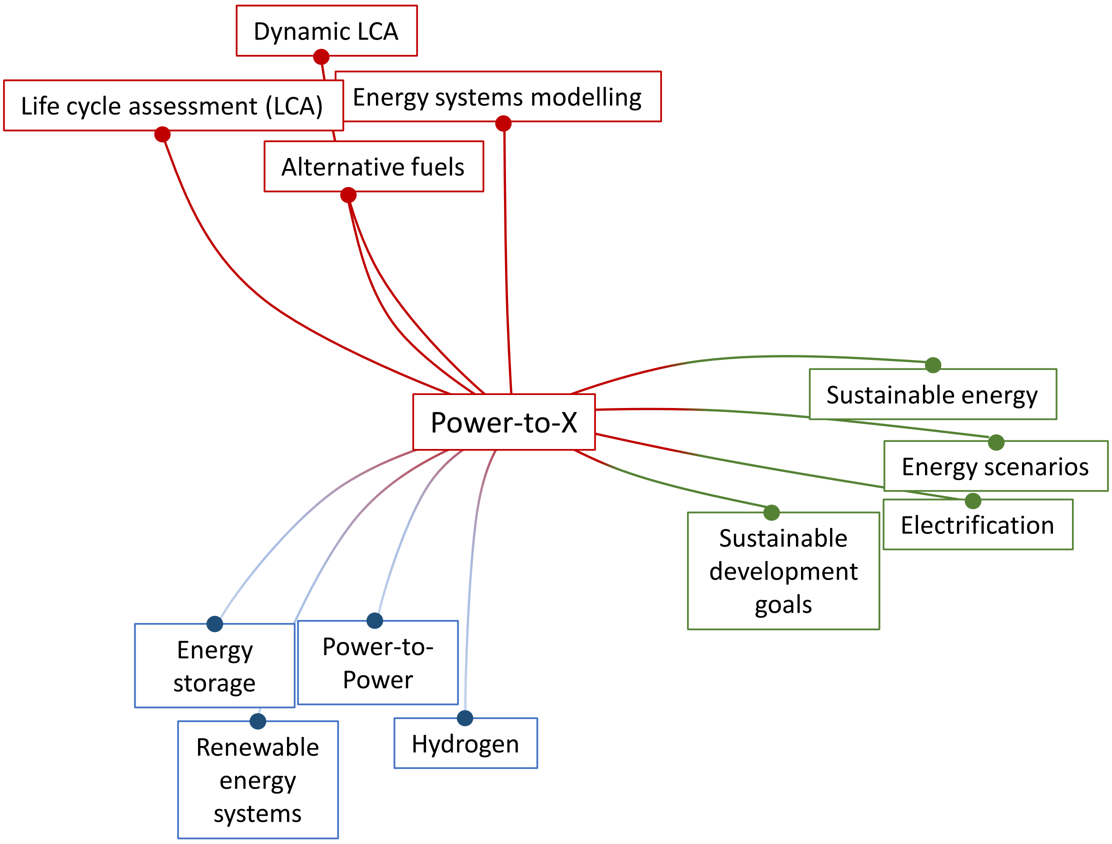


Figure 2.9. Interconnections of the keywords related to Power-to-X *[64]*

Germany is the leader in research and sponsorship of papers published in Power-to-X and has the largest installed Power-to-Hydrogen capacity, with 57 MW installed by 2022, followed by Spain with 25 MW [66]. The EU accounts for 90% of the papers published in this field. The main sponsor of research related to PtX technologies is the German Federal Ministry of Education and Research, followed by the program EU Horizon 2020. Recently, a study presented a literature review on the weaknesses and drivers of this technology in Europe; the study concludes that PtX is still at an early stage, where there is significant uncertainty about how the technology will penetrate the market [67]. The German energy transition drove PtX technologies at an early stage and found that the technologies required further cost reduction and an integrated system to produce high-temperature heat for the industry. [68]. The economic potential of PtX was also assessed in a literature review. The three most relevant markets were identified: a) the transportation sector, b) Power-to-Gas blended with hydrogen in the existing natural gas grid, and c) the power generation sector. [69]. A review and compilation of demonstration projects worldwide were synthesized by [70]. Most projects are in Europe (154), while 18 are being developed in North America, 13 in Asia, 5 in Oceania, and 2 in South America. In 2021, 130 Power-to-Hydrogen projects with 127 MW capacity were installed in the EU and UK, while in 2022, the number of projects reached 143 with 162 MW capacity [66]. In 2022, Denmark was the first country to agree on a specific Power-to-X Strategy [57]. The country expects to become an export partner of green hydrogen and e-fuels in the region.

2.3.1. Power-to-X plants

In Figure 2.10 selected projects in Germany in operation or that were built since 2010 are summarized when the concept of Power-to-X was not even developed yet [71]. Germany has several PtX plants, and also some are under construction and in planning.

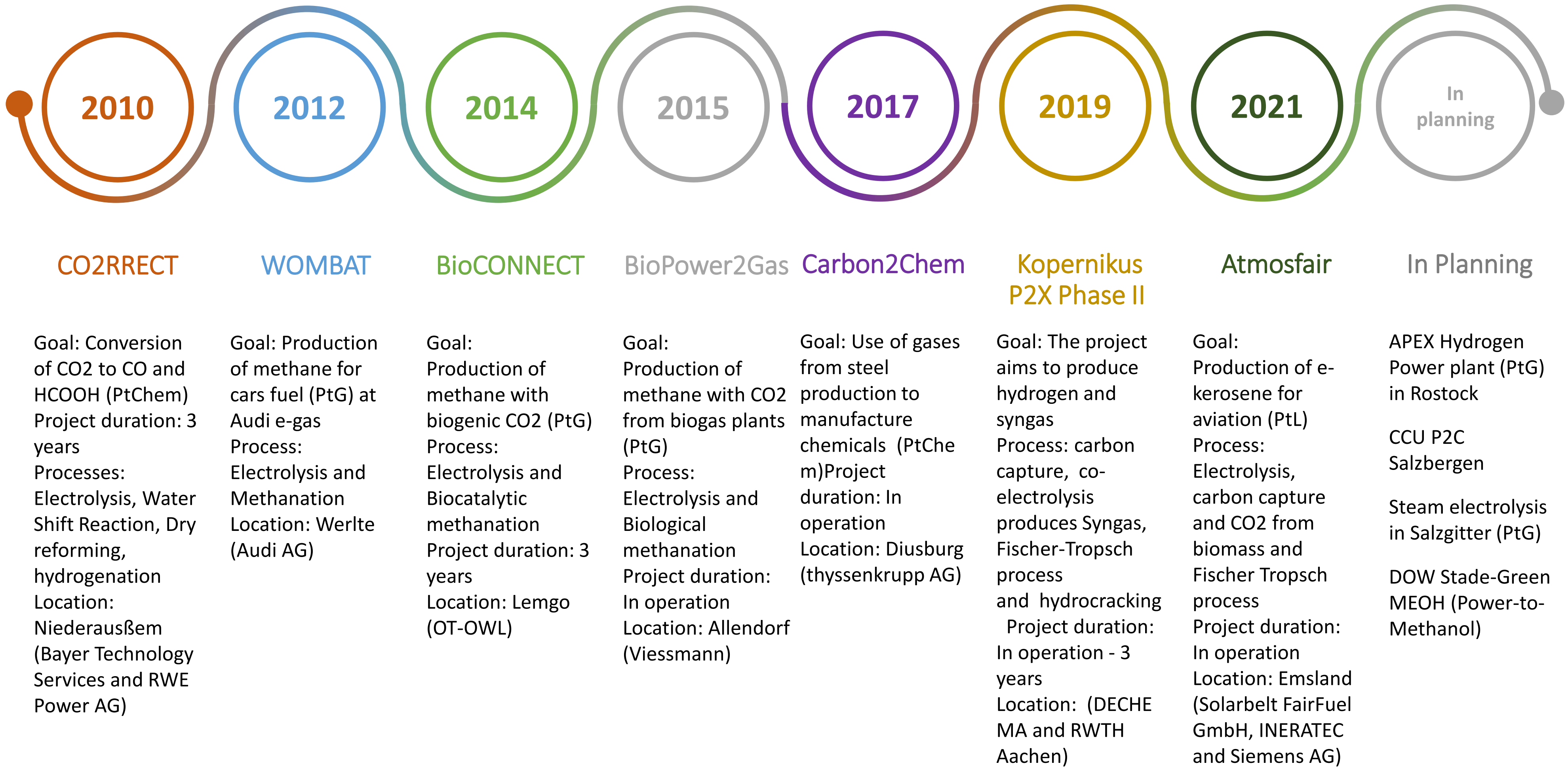


Figure 2.10. Description of the selected Power-to-X power plants located in Germany

The complete data on plants in Germany can be found in [72], and the entire table of projects can be found in the Kopernikus Project sponsored by the Federal Ministry of Education and Research of Germany in [73]. There are four main projects with different focuses as part of the Kopernikus initiative; the ENSURE project [74], P2X project [75], SynEnergy [76], and ARIADNE [77]. The ENSURE project is focused on the required modifications of the power grid to adapt it to renewable energy generation, whereas the P2X project is focused on the conversion of hydrogen to other energy carriers. The third project, SynEnergy cooperates with the industrial sector to adapt its electricity demand to the oscillation of supply from renewables. Finally, the project ARIADNE aims to guide the political decision process to fulfill the Paris Agreement and create strategies for the energy transition [78]. Germany announced in 2021 the H2Global project that should work as another funding platform for hydrogen-related projects. The German government is planning to assign 900 million US$ (converted from the original value in EUR, in this thesis 1 EUR→1 US$) for this purpose to promote a rapid PtX market rise-up [79]. It is expected to decrease over the course of time the amount of money provided by the government grants once the market works alone, and the demand is high enough [80].

In 2022, a methanol production plant in south Thuringia powered by their residual waste treatment plant (ZASt) was announced. The energy company in Essen expects to include in the project a 10 MW electrolyzer and a separation system of CO_2 from the exhaust gas flow from waste processing. It is expected to be built by the end of 2023 with an investment of 23 million US$ (converted from the original value in EUR) and produce 5,000- 7,000 t of clean methanol per year [81]. Other projects started in May 2021 as part of the investment plan in the Important Projects of Common European Interest (IPCEI) Hydrogen Technologies and Systems. In total, sixty-two German projects will receive over 8 billion US$ (converted from the original value in EUR) in state funds [82].

In 2023, a 100 MW electrolyzer and a hydrogen pipeline in northwest Germany are expected to start operation [83]. Additional electrolyzers are also planned; for example, the one in Saxony-Anhalt (35 MW) [84]. Also, in the region of Brandenburg an international center for PtX is planned for 2024. The project will be called “PtX Lab Lausitz” and will receive a total investment of 180 million US$ (converted from the original value in EUR) [85].

The German government is working on an H2Atlas Africa to identify potential hydrogen hubs and future partnerships to import green hydrogen from Morocco, Tunisia, Namibia, and South Africa [86]. For example, Germany and Morocco are investing in building a PtX industrial plant of 100 MW in electrolysis capacity; the plant in Ouarzazate (in Morocco) is supposed to be powered by solar energy [58].

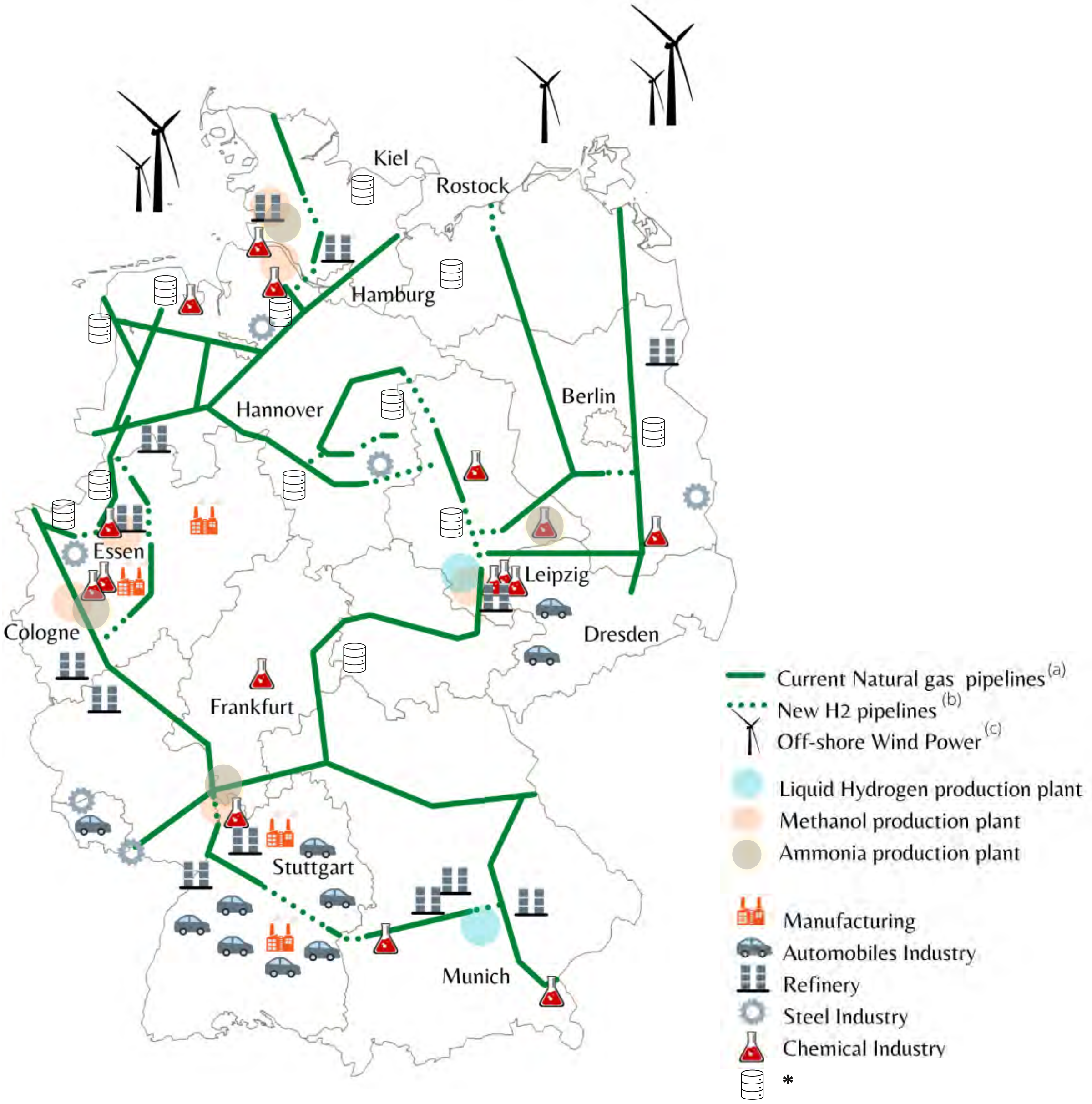
By 2028 a hydrogen hub in the port of Wilhelmshaven, Germany is expected. The port is supposed to be equipped with an ammonia cracker that could process 130,000 t/a of green hydrogen from green ammonia [87].

The majority of Germany's automotive industry is situated in the southern region, which is also home to numerous chemical plants (as shown in Figure 2.11). Consequently, the energy demand in southern Germany surpasses that of the northern part of the country.

Simultaneously, the greatest potential for wind energy in Germany lies in the northern region, where offshore wind capacity is projected to reach 20 GW by 2030 [88]. Moreover, the country's ports are located in the north, necessitating the transportation of energy carriers to the south. For example, the distance between the port of Wilhelmshaven and Munich is approximately 850 km. The existing natural gas pipelines in Germany are in green color in Figure 2.11, and with dotted lines, the pipelines that would need to be constructed to connect the current network for transporting hydrogen, either in its pure form or blended with natural gas.

However, converting thousands of kilometers of pipelines into hydrogen pipelines would incur significant expenses and require more time. Therefore, in the short term, alternative methods such as transporting hydrogen as liquid hydrogen, ammonia, or methanol are considered. In 2020, when the Hydrogen National Plan was released, Germany required 55 TWh of hydrogen for chemical production, including ammonia, methanol, and the petrochemical sector. However, 93% of this hydrogen was sourced from gray hydrogen. In the future, all hydrogen not derived as a byproduct from other industries should be produced as green hydrogen. By 2030, the country's hydrogen demand is projected to increase by at least 10 TWh [89].

Not only is Germany becoming a PtX hub, but also Denmark and other countries are investing in producing clean hydrogen energy carriers. In 2022, the construction of a 10 t/d plant to produce green liquid hydrogen in Casa Grande, Arizona, U.S. was announced [90]. Additionally, a hydrogen production facility with a production of 2.83×10^7 m^3/day of blue hydrogen at Baytown, U.S. is expected to be built by 2027 [91].



a) Potential conversion of existing natural gas pipelines to H_2 pipelines
b) Potential lines to connect the net
c) 1.1 GW of installed capacity in the Baltic Sea and 7 GW of installed capacity in the North Sea
*Potential cavern storage facilities

Figure 2.11. Map of natural gas pipelines in Germany and selected industries of the country that will need hydrogen. Updated from *[64]* and adapted from *[92], [88], [93]*

2.3.2. *“X” - Hydrogen gas as an energy carrier*

Power-to-Hydrogen gas is a process in which hydrogen is generated through electrolysis, employing electricity as the energy source. The resulting hydrogen can be directly injected into the gas grid or undergo methanation to transform it into synthetic gas. When renewable energy sources are utilized during this process, renewable gas is generated, which finds application in various sectors. This approach facilitates the storage of excess renewable electricity generated on days with abundant solar and wind resources, enabling it to be stored for extended durations [94].

In 2021, 94 million t of hydrogen were produced, but only 0.037% came from green hydrogen [18]. Large-scale hydrogen production via electrolysis is under development in many countries. Electrolyzers of hundreds of MW are being commissioned and proposed by the most competitive enterprises in the business [95]. Many enterprises announced their intention to build the largest electrolyzer in the world. However, currently, the common capacity of polymer electrolyte membrane (PEM) size is 1 MW per stack unit (450 kg_{H2}/day) [96], and the target for 2050 size is 10 MW stack units for PEM and alkaline water electrolyzer (AWE). The current lifetime of an electrolyzer stack is around ten years but is supposed to increase to thirteen years by 2050 [95]. Selected projects announced by some companies are presented in Table 2.3.

Different parameters of the most common electrolyzers used today, PEM and AWE, to produce green hydrogen are shown in Table 2.4. An extended table with all the assumptions for each value has been presented in [97].

Table 2.3. Selection of large-scale electrolyzer plants

Company	**Electrolyzer capacity (MW)**	**Planned start of operation**	**Location**	**Reference**
Siemens AG - Air liquid GmbH	200	2023	Normandy, France	[98]
Iberdrola – nel ASA	200	2023	Puertollano, Spain	[99]
Shell	200	2023	Rotterdam, The Netherlands	[100]
Vattenfall – Shell Global - Mitsubishi Heavy Industries	100	2025	Hamburg, Germany	[101]
Vatenfall GmbH – Preem Petroleum AB	200-500	2025	Lysekil, Sweden	[102]
Thyssenkrupp Uhde Chlorine Engineers GmbH	88	2023	Québec, Canada	[103]
Linde AG	24	2022	Leuna, Germany	[104]

Table 2.4. Comparison of electrolyzers: PEM and AWE

Electrolyzer	Specific energy use (kWh/Nm$^{3)}$	Energetic efficiency (based on LHV) (%)	Exergetic efficiency (%)	Levelized production cost of H_2 (US$/kg$_{H2}$)	Technology readiness level (TRL)
PEM	2.5-7.5 ([19] , [95], [105], [106])	56-80 ([5] , [6] , [106], [107])	62- 72.5 ([108], [109], [110] , [111], [112])	2.6-10 ([5], [113], [114], [115])	7-9 ([106], [116])
AWE	4.2 – 7.0 ([95], [105])	63 – 75(, [5], [6], [106], [117])	63-68 ([118], [119])	2.0-3.8 ([5], [14], [15], [120])	9 ([116], [106])

One of the reasons why the hydrogen economy is so attractive is due to the many applications and sectors that could benefit from this element. Apart from the main applications mentioned in the introduction, such as in refineries or as an energy storage vector, hydrogen can be used as a fuel in many sectors, such as [121]:

- The power sector. Either directly with gas turbine applications or fuel cells.
- In the heat sector.
- The high-energy consuming industries like steel and cement.
- The automotive sector. Currently, many hydrogen-driven cars are available in the market with fuel cell technology.
- The chemical industry to produce other chemicals.

Europe has thousands of km of pipelines for natural gas transportation, which could boost a quick transition and increase the hydrogen offer in the continent by blending natural gas and hydrogen in existing pipelines [122]. These pipelines can also be converted to pure hydrogen pipelines. The use of the current pipelines instead of the construction of new ones could also affect in a positive way the social acceptance of a hydrogen economy. Germany possesses over 511,000 km of natural gas pipeline available for distributing gas to the end consumer [123].

Also, new pipelines are being built in Europe, a hydrogen pipeline with a capacity of 2 million t/a of H_2 between Spain and France is expected to enter into operation in 2030 [124]. In Germany, the new 130 km H_2 pipeline from Lingen to Gelsenkirchen and the one from the Dutch border to Salzgitter will link the entire chain of production, storage, transport, and final use of green hydrogen. In Lingen, the electrolysis capacity will be expanded to 200 MW. For this integration, the partners want to jointly build the first publicly accessible hydrogen infrastructure and connect all sectors. The project includes the conversion of some existing pipelines to transport 100% hydrogen. This European initiative, when available, is expected to connect Germany, the Netherlands, Belgium, and France via a hydrogen network [125].

However, there are still some challenges to overcome when dealing with hydrogen. Hydrogen causes embrittlement and corrosion in the current pipelines used for natural gas [42], and particular materials such as polyethylene should replace the steel pipelines when dealing with percentages higher than 20 % of hydrogen mixture [126]. Hydrogen embrittlement occurs because hydrogen is a small element that easily diffuses in the metal, causing the metal ductility and resistance to fracture to decrease. In general, more control is required to avoid permeation and leaks of the hydrogen [127].

Companies producing gas turbine equipment have developed gas turbine systems equipped to handle up to 60% of H_2 in their turbines. The combustion of hydrogen is associated with several challenges that must be overcome to reach 100% hydrogen gas turbines. For instance, hydrogen can produce flashbacks and thermoacoustic variation. Also, it can easily auto-ignite and requires more control. Better NOx reduction systems are necessary due to the higher adiabatic temperature of the combustion [128].

The conversion of one block of a gas-fired combined-cycle power plant of 1.32 GW (Nuon Magnum power plant), located in Eemshaven (The Netherlands), is planned to run with 100% hydrogen by 2023. The gas turbine will run with blue hydrogen if the availability of green hydrogen is not enough [129].

Some additional factors of hydrogen losses should also be considered in the evaluation. For example, there are losses of ca. 0.5% per 100 km and 1% of the stored gas when transported by pipelines. Also, in compressed gas cylinders, losses of 0.5% are inevitable [130], [131].

Relevant details about hydrogen gas storage conditions and infrastructure are summarized in Table 2.5.

Table 2.5. Relevant information about the storage and infrastructure of hydrogen

Storage conditions	It can be transported as a gas at environmental temperature and different pressures. 250 bar, 400 bar and 700 bar is commonly used [132], [26]
Infrastructure	It is possible to transport 100% hydrogen or hydrogen blended with natural gas in pipelines. It can also be transported as compressed gas via truck or ship. The infrastructure is available and currently being developed quickly for large-scale deployment.
TRL	8

Table 2.6. Environmental-related data for hydrogen

Toxicity	Not toxic
CO_2 emissions	No CO_2 emissions when combusted
NOx emissions	Possible when combusted since the temperature flame is higher

Hydrogen can be produced at a levelized cost of 5.8-10 $US\$_{2019}/kg_{H2}$ from wind electrolysis [133], while hydrogen produced by the steam reforming process costs 1.25-3.5 $US\$_{2018}/kg_{H2}$ [132]. The hydrogen production from PEM electrolysis has a specific energy use (SEU) of (4.4-6.5) kWh/Nm^3 [95]. The cost of storage of compressed hydrogen (250-300 bar) has been reported as 32 $US\$_{2020}$ /MWh (converted from the original value in GBP, in this thesis 1 GBP → 1.2 US$), and for hydrogen transportation, 25 $US\$_{2020}$/MWh [134].

Currently, natural gas prices are increasing worldwide, which could prevent hydrogen from blending with natural gas to become more popular. The NG price is increasing due to different factors, including political decisions to tax CO_2 emissions; the energetic/transportation crisis derived from the pandemic; political and military conflicts [135], [136].

The 94 million t of hydrogen produced in 2021 represented 900 million t of CO_2 emissions associated with its production. When combusted, the CO_2 emissions from green hydrogen are zero, while from NG, when converted to hydrogen, are 9.7 kg_{CO2}/kg_{H2}. Even if carbon capture storage technologies are used to prevent the release of these emissions, about 1 kg_{CO2}/kg_{H2} cannot be prevented [137]. A substitution of 20 % H_2 in NG combustion corresponds to a decrease of 6 - 7 % in greenhouse gas emissions [138]. In Table 2.6 selected environmental data related to hydrogen are presented [16].

2.3.3. "X"- Liquid hydrogen as an energy carrier

Hydrogen was first liquefied in 1898 [139]. The liquefaction of hydrogen takes place at atmospheric pressure and at a cryogenic temperature of -252.8 °C [25]. For its liquefaction, a cryogenic working fluid such as helium is required due to the low temperatures it reaches. The basic principles of gas liquefaction can be found, for example, in [140], and relevant information about LH_2 can be found in Table 2.7.

Table 2.7. Important information about the liquid hydrogen energy carrier "X"

Demand	The global demand for LH_2 is projected to increase at an annual growth rate of over 5% by the period of 2023-2028 [90]. LH_2 consumption in the U.S. is expected to reach 42,300 t in 2024 [141]. The highest market, however, is the Asia-Pacific region.
Energy to extract H_2 (kJ/mol_{H2})	0.907 [26]
Specific energy use for H_2 liquefaction	(13.6 – 6.0) kWh/kg_{LH2} [20] 0.30 kWh/kWh_{H2} [142]

Some of the applications for LH_2 are [143]:

- In the aerospace industry, as fuel for oxygen-fueled combustion rockets.
- In the petrochemical industry, it is used in refineries and in hydrotreating and hydrocracking processes.
- In metallurgy, it is used for annealing metals.
- LH_2 is also used in the chemical industry.

LH_2 is possible to transport in insulated trucks or vessels. Hydrogen is the smallest element in the periodic table; therefore, when liquefied, the volumetric content (kg_{H2}/m^3) increases, as shown in Table 2.1. Up to 3500 kg_{LH2} can be transported in a single standard truck [144], as a gas, only 900 kg_{H2} can be transported [145]. The minimum distance for economically significant transport of liquid hydrogen (liquefaction and transportation costs) varies from study to study; some reports suggest that liquid hydrogen vessels are necessary for distances over 1000 km [114]. Other authors report shorter distances [146]. The distance also depends on the amount of hydrogen transported [114]. Large containers of high-pressure gaseous hydrogen are expensive, while the distribution of liquid hydrogen does not vary much with the distance. What is clear is that for intercontinental hydrogen distribution, a denser form of hydrogen supply must be considered.

Some additional factors of liquid hydrogen losses should be considered in the evaluation [131], such as the "boiled-off" of LH_2 during its transportation or storage, with a maximum recommended storage time of 10 days. Based on experimental data, boil-off losses can vary from 2% - 15% depending on the scale of the delivered LH_2 (1,800 kg/day - 100 kg/day, respectively) [147]. Another challenge is the conversion of ortho-hydrogen to para-hydrogen [148]. The problem occurs due to the higher energy state of ortho-hydrogen compared to para-hydrogen. The ortho-para hydrogen conversion (o-p-conv) is an exothermic reaction [149]. Thus, the exothermic reaction of the o-p-conv of the liquefied hydrogen would evaporate some of the stored liquid hydrogen. A catalytic o-p-conv during the liquefaction process is required to minimize the boil-off losses during storage and transportation [150]. Additional refrigeration capacity must remove the released heat from the hydrogen liquefaction system [31]. The additional specific minimum theoretical work caused by the o-p-conv of the liquefaction process for a product at 1 bar is 0.553 – 0.59 kWh/kg_{H2} [151]. Commercial LH_2 production generally operates with a product para-hydrogen fraction of at least 95 % [152].

The duration of LH_2 long-distance transportation can be found in [153]**.** Relevant information about the storage conditions and infrastructure of LH_2 is summarized in Table 2.8.

The first large-scale liquid hydrogen vessel (1250 m^3) became operational in 2022. The LH_2 ship transports LH_2 from Australia to Japan [154].

South Korea's largest hydrogen liquefaction plant entered into operation in 2022 with a total capital investment of 210 million US$ and a production of 13,000 t/a of LH_2. With this investment, South Korea expects to move towards the decarbonization of its automotive industry [155]. Furthermore, the market of liquid hydrogen plants is only increasing; in 2023, another company plans to build a 30 t/d hydrogen liquefier in the U.S. [156]. A recently announced LH_2 plant will provide another 30 t/d of LH_2 in this country [90]. A comparison of theoretical and real parameters for liquid hydrogen plants is presented in Table 2.9.

The levelized cost of production of blue LH_2 from fossil fuels, including CCUS, is 1.4 - 3.4 $US\$_{2020}/kg_{LH2}$, while green LH_2 is approximately two or three times higher [14]. The levelized cost of green LH_2 production depends intensely on the cost of green hydrogen [157]. A levelized cost of production of 7.95 $US\$_{2020}/kg_{LH2}$ of green LH_2 was reported for Germany [97]. The cost of the liquefaction alone was collected in [142] for different years in operating plants with an average CAPEX unit cost of 1350 $US\$_{2019}/kW_{H2}$. The specific energy use is reported in a range of (6 – 13.6) kWh/kg_{LH2} [20] or 0.30 kWh/kWh_{H2} [142].

As shown in Table 2.9, the respective specific energy use of real liquefaction plants is between 10 – 15 kWh/kg_{LH2}, much higher than the theoretical ones [158]. Several conceptual hydrogen liquefaction processes with significant improvements in energy and exergy efficiency have been suggested in the literature. For instance, a helium-neon cycle with a three-stage propane Joule-Thompson cycle for pre-cooling and continuous ortho-para conversion of hydrogen has been introduced in [159]. Also, a mixed refrigerant cycle has been evaluated in [160]. A large-scale hydrogen liquefaction plant with a helium cycle was presented in [161]. A supercritical helium cycle with stagewise ortho-para conversion for a small pilot plant and a large-scale plant was proposed in [162]. Another large-scale liquefaction plant with two combined mixed refrigerants cycles for the pre-cooling of hydrogen to 74−95 K, and further achieving the temperature of 21 K was discussed in [163]; six possible alternatives of this concept were evaluated. In [164], two arrangements of cycles have been reported for the pre-cooling of hydrogen to a temperature of 110 K. The first concept included a hydrogen Claude cycle, whereas the second concept applied a hydrogen/neon cycle for the pre-cooling and a hydrogen Claude cycle for the liquefaction. In addition, a system with liquid nitrogen pre-cooling and cryogenic helium cycle with stage-wise ortho-para conversion that is reported in [165] should be mentioned as well.

Table 2.8. Storage and infrastructure for liquid hydrogen

Storage conditions	LH_2 storage requires a cryogenic temperature of −252.8°C at environmental pressure [166].
Infrastructure	Possible to transport in insulated trucks and vessels (only 1 in the market).
TRL	7

Table 2.9. Comparison of the exergy efficiency and specific energy use of hydrogen liquefaction plants.

Reference	**Exergy Efficiency (%)**	**Specific energy use** (kWh/kg_{LH2})	**Feed conditions**	**Product conditions**	**Capacity (TPD)**
Ingolstadt plant* [160]	21.0	13.6	20 bar 308 K	1.3 bar 21 K Para > 95 %	4.4
Leuna plant [160]	23.6	11.9	24 bar 313 K	1.3 bar 21 K Para > 95 %	5
[159]	56.8	6.9	1 bar 300 K	1 bar 20 K Para > 99 %	170
[160]	44.5	6.5	21 bar 310 K	1 bar Sat. liquid Para > 98.5 %	86
[167]	47.7	5.3	60 bar 300 K	1.5 bar 20.0 K Par = 99.8 %	860
[168]	54.0	5.4	21 bar 298 K	1.3 bar 20 K Para 99 %	100
[169]	39.5	7.7	21 bar 298 K	1.3 bar 21 K Para 95 %	100
[164]	45.0	5.9	25 bar 303 K	2 bar 22.8 K Para > 98.5%	100
[170]	25.5	13.8	298 K	-	90
[163]	45.5	6.5	21 bar 298 K	1.3 bar 21 K Para 96 %	90

2.3.4. "X" - Ammonia as an energy carrier

Ammonia (NH_3) was first synthesized in 1913, with the well-known Haber-Bosch synthesis process still used today [171]. Almost all the ammonia today is synthesized from hydrogen and nitrogen (Eq. (2.1)), and the source of hydrogen may vary but primarily is obtained from fossil fuels. Relevant parameters of ammonia are summarized in Table 2.10.

$$3H_2 + N_2 \leftrightarrow 2NH_3 \qquad (2.1)$$

Table 2.10. Important parameters of the ammonia energy carrier "X"

Demand	In 2021, 150 million t of ammonia were produced worldwide [172].
Lower heating value (MJ/kg)	18.8 [173]
Volumetric H_2 content in liquid ammonia (kg_{H2}/m^3)	121 [174]
Specific energy use for ammonia production (kWh/kWh_{NH3})	0.079 [142]
Energy to extract H_2 (kJ/mol_{H2})	30.6 [26]
Explosion limits in air (%)	15-28 [26]

The main industries that require ammonia are [8]:

- The agricultural industry as a fertilizer.
- The refrigeration industry as a working fluid.
- Manufacture of explosives and other chemicals.
- Ammonia can also be a fuel:
    - Direct use of ammonia for fuel cells [175].
    - Pure ammonia or a blend of NH_3 and H_2 for fuel engines [176].
    - Co-firing NH_3 with H_2 is also possible using gas turbine technology [177].

Today, many reports show that ammonia can contribute to decarbonizing many sectors currently dependent on fossil fuels, for instance, the container shipping industry. The long-distance transportation of hydrogen can be performed in ships powered by clean ammonia [114]. Ammonia is expected to become the largest hydrogen carrier due to the technically simple storage and transportation conditions and well-established logistics to the end-users [178]. Ammonia-powered ships are expected to operate by 2025 after developing an ammonia dual-fuel engine [177]. In Table 2.11 relevant information about the storage conditions and infrastructure of NH_3 is presented.

Table 2.11. Information about storage and infrastructure for ammonia

Storage conditions	Ammonia can be transported in liquid form at a temperature of -33 °C and environmental pressure or environmental temperature and a pressure of 8 bar [179].
Infrastructure	Possible to transport in trucks and vessels. The infrastructure is globally developed since many years ago [180].
TRL	9

Table 2.12. Environmental-related data for ammonia *[8]*

Toxicity	Highly toxic if leaked
CO_2 emissions	No
NOx emissions	Possible

The cost of green ammonia is approximately double the price of conventional production of ammonia from fossil fuels [181], [171]. The cost of green ammonia depends on the amount produced and the cost of green hydrogen. For instance, a levelized cost of production of green ammonia of 650 $US\$_{2020}/t_{NH3}$ has been reported in [181]. Other analysis reports a cost of green ammonia of 4.4 $US\$_{2020}/kg_{H2}$, corresponding to 700 $US\$_{2020}/t_{NH3}$, while a cost of ammonia from blue hydrogen of 2.2 $US\$_{2020}/kg_{H2}$ [182]. A cost of 570 $US\$_{2020}/kW_{NH3}$ was reported in [142] for an existing plant in 2018. The shipping and storage cost of ammonia has been calculated as 8.8 $US\$_{2020}$/MWh (converted from the original value in GBP). The transport cost of 5.3 $US\$_{2020}$/MWh (converted from the original value in EUR) and the cracking of ammonia for reconversion to hydrogen cost has been reported as 160 $US\$_{2020}$/MWh [134]. The specific energy use of the ammonia conversion is 0.079 kWh/ kWh_{NH3} [142]. While the SEU of the ammonia cracking reported is 30.6 kJ/mol_{H2} [26].

Ammonia does not contain carbon, making it carbon-free, like pure hydrogen, unlike most other fuels. However, one disadvantage of ammonia is its high toxicity for humans and aquatic life if leakages occur in water sources. More information is presented in Table 2.12.

2.3.5. "X" - Methanol as an energy carrier

Methanol (CH_3OH) is a worldwide used chemical also known as wood alcohol or methyl alcohol [183]. In conventional methanol production from fossil fuels, methanol is produced from syngas via hydrogenation of CO and CO_2 and reverse water-gas shift reaction [184].

Different combinations of producing methanol to reduce carbon emissions have been studied. The methanol production from pure CO_2 and pure H_2 (as seen in Eq. (2.2)) has several advantages over the conventional process since it results in fewer by-products and, at the same time, needs less energy [185]. Currently, about 65% of methanol production is based on natural gas reformation (gray methanol), while the rest (35%) is mainly based on coal gasification (brown methanol) [186]. Relevant parameters related to methanol are found in Table 2.13.

$$2CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \tag{2.2}$$

Table 2.13. Important parameters of the methanol energy carrier “X”

Demand	In 2022, 110 million t of methanol were produced worldwide, making it one of the most highly synthesized chemicals after ammonia, but it is expected to equal ammonia production in 2030 [187] and reach 500 Mt/a by 2050 [184]. However, currently, less than 0.2 Mt is produced as clean methanol (mainly as bio-methanol) [184].
Lower heating value (MJ/kg)	20.1 [173]
Volumetric H_2 content in methanol (kg_{H2}/m^3)	99 [174]
Specific energy use for methanol production (kWh/kWh_{CH3OH})	0.08 [142]
Energy to extract H_2 (kJ/mol_{H2})	16.3 [26]
Explosion limits in air (%)	6.7-36 [26]

Methanol is mainly used for [184]:

- Production of other chemicals, such as formaldehyde, acetic acid, and plastics.
- It is also used as fuel for ships, industrial boilers, and cooking.
- Methanol could potentially substitute or be mixed with gasoline. Methanol's flame has higher octane than gasoline, and the current gasoline engines could be used with minor changes [188].

Clean methanol is an alternative option for feasible hydrogen transportation over long distances due to the simple storage conditions. Relevant information about the storage conditions and infrastructure of CH_3OH is summarized in Table 2.14.

Table 2.14. Information about storage and infrastructure for methanol

Storage conditions	It can be efficiently transported in liquid form at environmental pressure and environmental temperature [184].
Infrastructure	Available and globally developed since many years ago [184]. It is possible to transport it by ship or truck. Methanol-powered ships are not available yet, but this is feasible from a technical point of view [177].
TRL	9

Table 2.15. Environmental-related data for methanol *[184]*

Toxicity	Toxic if leaked
CO_2 emissions	Yes
NOx emissions	No

The methanol production cost via direct CO_2 hydrogenation is 2–2.5 times higher than the cost of the conventional process [189]; also, methanol production via CO_2 hydrogenation consumes more utilities than conventional methanol production [190]. The levelized cost of production of green methanol is 800-1,600 $US\$_{2021}/t_{CH3OH}$ [184]. Other reports estimate the range is 1,120-2,380 $US\$_{2021}/t_{CH3OH}$, while the fossil fuel-based variation could be produced at 100-250 $US\$_{2021}/t_{CH3OH}$ [184]. In a recent study, green methanol production and transportation cost from Saudi Arabia to Germany was estimated to be 0.49-0.60 $US\$_{2021}/kg_{CH3OH}$ [191]. A cost of 607 $\$_{2021}/kW_{CH3OH}$ was reported in [142] for an operating plant in 2020. The SEU of the methanol production is 0.08 kWh/ kWh_{CH3OH} [142], while the dehydrogenation energy use has been reported as 16.3 kJ/mol_{H2} [26].

The estimated annual emissions of methanol production amount to 0.3 Gt of CO_2, approx. 10% of the total CO_2 emissions of the petrochemical sector [184]. More environmental parameters related to methanol are summarized in Table 2.15.

2.4. Regasification of liquid hydrogen

As mentioned before, hydrogen can be transported in liquid form over long distances and further regasified at the delivery port. The most developed liquid hydrogen chain project exists between Japan and Australia. In February 2022, this ship carried brown liquid hydrogen to the port of Kobe, Japan, from Victoria, Australia [192]. Once at the port, it must be regasified in a big regasification facility or transported in insulated trucks to its final destination and regasified in smaller hydrogen vaporizers in situ. Neither Japan nor the EU has any hydrogen regasification ports. The port of Rotterdam, The Netherlands, intends to become a hydrogen hub for Europe [193]. It is unclear which energy carrier will be used for the imported hydrogen, but if it is liquid hydrogen, a large-scale regasification plant would be useful to transport the hydrogen via the EU gas pipelines or directly use it near the port. Currently, only atmospheric vaporizers are commercially available for small-scale LH_2 regasification [194]. For the small-scale atmospheric vaporizers of hydrogen fueling stations, a specific energy use of 1.7 kWh/kg_{H2} is reported [130]. The LH_2 chain is similar to the LNG chain. However, the middle-scale and large-scale LH_2 regasification systems are not intensively addressed yet.

Although almost every possible edge of the hydrogen economy is being studied, very few recent studies discuss the challenge of large-scale regasification of liquid hydrogen. There are currently mostly very old studies on the regasification of liquid hydrogen. Most of the proposed configurations are over twenty years old and do not consider a large-scale scenario for the hydrogen regasification plant. Also, none of the reviewed publications divide physical exergy into mechanical and thermal, as it is required for a system dealing with cryogenic temperatures.

Table 2.16. Information about hydrogen regasification plants *[142]*.

Plant	**Year**	**Specific energy use (kWh/kWh_{H2})**	**CAPEX cost per unit (US$/$kW_{H2}$)**	**Project**
1	2016	0.01	112	North of England, H21
2	2019	0.002	114	N.A.
3	2019	0.005	432	N.A.

Table 2.17. Hydrogen regasification publications so far and important parameters

Reference	**Year**	**Specifications**	**Working fluid exchanging heat with the LH_2**	**Energetic (or exergetic*) efficiency (%)**	**Thermodynamic properties of Hydrogen**
[195]	1978	Stirling cycle (LNG and LH_2)	Helium	53	Not mentioned (100% para-hydrogen)
[196]	1993	Includes a sub-system consisting of a Rankine cycle with a cryogenic working fluid.	Nitrogen, Argon, and Methane	N.A.	Not mentioned
[197]	1996	OGT and a bottoming CGT cycle with cooling using regasification of LH_2	Helium	66-79	Not mentioned
[198]	1996	Combined system using closed-cycle helium turbine with two exergy sources	Helium	80.6 (76.7*)	Taken from [199]
[200]	1996	Application for power trains (LNG and LH_2). Stirling cycle	N.A.	N.A	Not mentioned
[201]	2007	Gas-turbine systems with magnetohydrodynamic systems, helium closed cycle, and combined systems.	Helium	64.5 - 75.3	Properties of real fluids were used [202].
[203]	2008	Semi-closed recuperative gas turbine cycle	Nitrogen	73 (45*)	LK-PLOCK method (Lee–Kesler–Plocker equation)
[204]	2019	Processes evaluated: supercritical and transcritical	Helium	35 – for supercritical 32- for transcritical	Modified equation of state Benedict-Webb-Rubin

From the very limited information reported on existing LH_2 regasification plants, there were at least three identified, but the scale and technology are unknown. In Table 2.16, the little information found is summarized [142].

The theoretical regasification papers found in the literature are described in Table 2.17. Recently, a study with a review of most of the hydrogen regasification papers was published by the author and three more coauthors [205].

Ref. [206] examined the exploitation of low-temperature LNG (-160°C) regasification as a heat sink for a closed gas-turbine system. This concept has been widely incorporated in the majority of publications concerning LH_2 regasification.

Ref. [195] is among the initial publications that discussed the regasification of LNG and LH_2. The generation of electrical energy is through a cryogenic-type Stirling Engine, where the environmental heat serves as the heat source, and the low-temperature heat of LH_2 (-252.8°C) or LNG (-160°C) serves as the heat sink. The theoretical investigation focuses on a large-scale system, while the feasibility of the engineering concept has been experimentally verified using a small-scale system (it would correspond to a TRL 3-4). Only the two-phase process of LNG and LH_2 was taken into account for the Stirling Engine, with the superheating of these substances to environmental conditions achieved by utilizing seawater as a heat source. However, a drawback of this proposed system is the substantial power consumption by seawater pumps, especially for hydrogen, which amounts to 5800 t/h for LH_2 compared to 4600 t/h for LNG. The paper considers the thermodynamic properties of para-hydrogen, reporting a latent heat of 445.6 kJ/kg (for CH_4 is 510.3 kJ/kg) and a sensible heat of 4011.0 kJ/kg (for CH_4 is 403.5 kJ/kg). The reported Carnot efficiency for the Stirling engine, using both LNG and LH_2 as working fluids, is 60%, with the calculated energy efficiency being 53% for LH_2 and 31% for LNG. However, the energy efficiency calculation does not take into account the impact of LH_2 or LNG regasification. The term "residual cold" is used to describe the remaining cold energy, which is reported as 44 MW within the temperature range of 124-270K for LH_2 and 2.4 MW within the range of 247-270K for LNG. Throughout the LH_2 regasification process, the pressure decreases from 10 to 5.5 atm, while it drops from 14 atm to 5.0 atm for LNG.

The paper [196] highlights the utilization of LH_2 regasification to enable high-pressure fuel supply through hydrogen injection into the engine. The proposed technical concept involves incorporating a Rankine cycle with a cryogenic working fluid (such as nitrogen, argon, and methane) as a sub-system to leverage low-temperature LH_2 as a heat sink while utilizing atmospheric heat (or exhaust gas) as the heat source to generate additional power. Although the authors mention that this sub-system contributes to improving overall efficiency, they do not specify the extent of the increase. Experimental results demonstrate the feasibility of the suggested system at a TRL of 3-4. In the process, LH_2 is compressed to a pressure of 8 MPa using a cryogenic LH_2 pump. To drive the LH_2 pump, a portion (10-20%) of the high-pressure

LH_2 is heated using atmospheric heat, expanded, and then supplied to the main engine. However, the definition of efficiency is not provided.

The functioning of closed gas-turbine cycles utilizing heat sinks at cryogenic temperatures is discussed in [197]. The operational parameters of the 50 MW helium turbine located in Oberhausen II, Germany, served as a basis for comparison. The LNG regasification process is presumed to occur at a pressure of 25 bar, while the assumed pressure for LH_2 was 5 bar.

[198] discusses a configuration where an integrated LH_2 regasification process serves as the low-temperature heat sink for a series combination of open-cycle and closed-cycle gas-turbine systems. The closed gas-turbine cycle used helium as the working fluid. The study conducted energy and exergy analyses, reporting the irreversibilities within each component of the entire system. By varying the regenerator effectiveness within the regenerative helium cycle from 0.5 to 0.95, the overall efficiency demonstrated an increase from 79% to 81.5%. The LH_2 regasification process was examined at a pressure of 10 MPa with an expansion down to 0.5 MPa. The overall energy efficiency was determined to be 80.6%, with an exergy efficiency of 76.7%. Depending on the utilization of gaseous hydrogen, the hydrogen expansion process could be omitted, resulting in energy and exergy efficiencies of 72% and 68.5%, respectively. It's worth noting that the exergy efficiency definition did not incorporate the regasification effect. The thermodynamic properties of hydrogen were taken from [199].

In [200], the authors conducted an assessment of the physical and chemical exergy to determine the overall efficiency of vehicle power trains. They calculated the physical exergy of LH_2 to be 12,483 kJ/kg at a pressure of 1.5 bar within the temperature range of 21K to 300K. For LNG, the physical exergy was determined to be 1,068 kJ/kg at a pressure of 1.5 bar from 116K to 300K. The LH_2 process was divided into 46% transition phase and 54% superheating, while for LNG, the distribution was 74% transition phase and 26% superheating. The energy generation system employed the Stirling cycle, with a particular emphasis on discussing the fuel cell component of the system. However, the efficiency of the process was not reported.

Hydrogen regasification was also addressed in [201]. The authors conducted evaluations on various gas-turbine systems, including a thermodynamically reversible (ideal) model. They also considered systems utilizing helium as a working fluid, magnetohydrodynamic systems with potassium-seeded helium closed cycles, and combined systems. However, the definition of energy efficiency remains unclear. The authors primarily focused on conducting a comparative analysis between real and ideal systems. The reported energy efficiencies were 64.5% and 75.3%, respectively. The properties of real fluids were used [202].

Another hydrogen regasification paper was published by [203]. The nitrogen semi-closed recuperative gas turbine cycle incorporates the thermal integration of LH_2 regasification. The reported energy efficiency of the cycle surpasses 73%, while the exergy efficiency stands at

45%. Although the effect of LH_2 regasification was considered in determining the exergy efficiency, it was not accounted for in the energy efficiency. The LH_2 regasification process is assumed to occur at a pressure of 100 bar. The LH_2 evaporator represents the component with the highest exergy destruction. To simulate the process, Aspen Plus software was used. The thermal properties of hydrogen were determined using the LK-PLOCK method (Lee–Kesler–Plocker equation). In the temperature limit of 20 – 100 K most of the differences were observed. The model was validated using the data from [25].

The most recent paper found addressing hydrogen regasification is [204]. The system under evaluation resembles a Stirling cycle, with the heat derived from the environment serving as the heat source. The definition of energy efficiency did not incorporate the impact of LH_2 regasification. The regasification process assumed LH_2 to be 100% para-hydrogen, and the ortho-para conversion was taken into account. The thermodynamic properties are calculated using the modified Benedict-Webb-Rubin equation of state [207]. The evaluation included a para-hydrogen supercritical process at 250/70 bar and a transcritical process at 60/4.

Chapter 3. Systems

The systems considered for comparison in this section are related to the four Power-to-X configurations mentioned before Power-to-Hydrogen gas, Power-to-Liquid hydrogen, Power-to-Ammonia, and Power-to-Methanol. As explained in Chapter 2, the second configuration, Power-to-Liquid hydrogen, has been selected for a deeper analysis. The end result of the four systems will be hydrogen gas for easier comparison. However, it should be noted that the reconversion to hydrogen is not necessarily required for ammonia and methanol.

3.1. Hydrogen gas

The system consisting of the production of hydrogen gas (that can potentially be blended with natural gas) has two phases, the use of electricity to produce the green hydrogen via electrolysis and further compression of the gas. This will be called the *charging phase* since electricity is being "charged" to the system. Secondly, the *storage and transport phase* is when the gas is distributed for further use. The two phases of the hydrogen gas chain are shown in Figure 3.1.

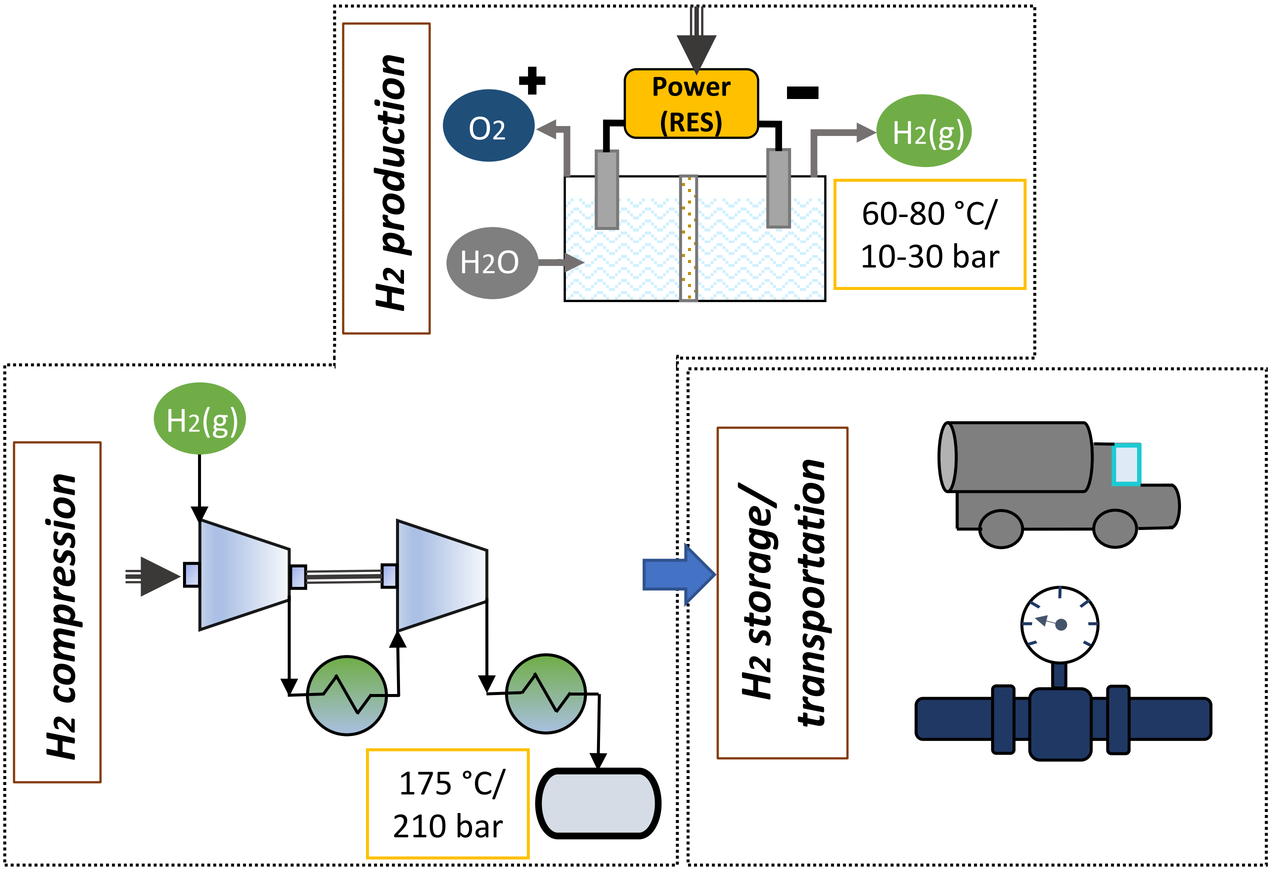


Figure 3.1. Description of the hydrogen gas chain within a hydrogen economy

After green hydrogen is produced at 60-80 °C and 10-30 bar from PEM electrolysis process [208], it has to be compressed to 200-500 bar to be transported either by trucks or compressed to a maximum 210 bar to be transported via pipelines [209]. Typically, H_2 pipelines used in the oil industry operate between 30-83 bar [210]. If the hydrogen is blended with natural gas for distribution, the pressure should be < 16 bar. At this pressure, a blend of 10% hydrogen is unproblematic. For steel pipelines, a 25% of hydrogen blend is feasible. For blends of over 40%, special alloys are required for the pipelines, and the NG compressor has to be replaced [138].

3.2. Liquid hydrogen

The system of the liquid hydrogen chain consists of three phases. The first phase corresponds to the production of green hydrogen via electrolysis and the further liquefaction of this gas. This phase is called the *charging phase* since electricity is being “charged” to the system. Secondly, the *storage and transport phase* is when the liquid hydrogen is distributed for further use. Finally, the *discharge phase* corresponds to the regasification of the liquid hydrogen to deliver it as hydrogen gas for further use, and electricity is produced or “discharged” in the cogeneration system of power and hydrogen gas. In Figure 3.2, the entire chain, including the *charging, storage, and discharge phase* for the liquid hydrogen chain is presented.

Taking into consideration the few existing studies about low-temperature heat utilization for LH_2 regasification, the LH_2 chain shown in Figure 3.2 will be deeper discussed and evaluated in this thesis. Therefore, the detailed parameters of the streams for the hydrogen liquefaction configuration are shown in detail in Figure 4.3 and Table 4.1. Furthermore, the details of the configuration and stream parameters for the regasification of hydrogen are shown in Table 4.3 and Figure 4.4.

After the green hydrogen is produced, it can be liquefied. Many different configurations exist for the liquefaction of hydrogen [158]. The one described in Figure 3.2 follows the configuration of [167] modified as presented in [97]. The hydrogen is first compressed to 60 bar and 26 °C and undergoes a liquefaction process until it reaches -252.8 °C and 1.3 bar. The helium cooling cycle operates with pressures in the range of 1.5 bar to 40 bar and temperatures of -255.15 °C to 209 °C. The assumptions and parameters for the liquid hydrogen simulation are shown in Table 3.1.

The liquid hydrogen regasification cogeneration system proposed in Figure 3.2 has been developed using an analogy with the LNG regasification in [206] and the adaptation in [198]. The configuration consists of three sub-systems:

1. Open cycle gas turbine system (OGT) simulated by taking into account an aero-derivative gas-turbine system of General Electric LMS-100M [211] that can be

modified to blend up to 30% hydrogen with NG by a simple retrofitting of the gas turbine [212].
2. Closed-cycle gas turbine system - with regeneration (CGT-R) using helium as the working fluid with a minimum pressure of 2.8 bar.
3. LH_2 regasification process.

The assumptions considered for the simulation of the liquid hydrogen regasification cogeneration plant (based on [213]) are presented in Table 3.2.

After hydrogen liquefaction, at least 20% of the available energy is lost. During the transportation of liquid hydrogen for 8,000 km, about 7% of the energy is lost, and during the regasification, no energy is lost since the system can generate power itself. Overall, the entire liquid hydrogen chain remains with ca. 73% of the initial energy available from the green hydrogen produced [18] (not considering the energy that can be produced from the OGT and CGT-R during the regasification process).

Table 3.1 Parameters for the simulation of the hydrogen liquefaction

Parameter	**Value**
Para H_2 fraction of the product (%)	> 98.5
Ortho-para conversion	continuous
Pressure ratio within H_2 compressors	2.8
Isentropic efficiency, compressors (%)	85
Isentropic efficiency, expanders (%)	90
Temperature after hydrogen intercoolers (°C)	26
H_2 mass flow (kg/s)	0.56
Helium mass flow (kg/s)	7.4
Heat exchangers ΔT_{min} (°C)	2

Table 3.2 Parameters for the simulation of the liquid hydrogen regasification

Cycle	**Parameter**	**Value**
OGT	Isentropic efficiency, compressors (%)	90
	Isentropic efficiency, expander (%)	94
	Pressure ratio within air compressors	6
	Pressure ratio of the cycle	42
	Temperature after intercooler (°C)	113
	Adiabatic combustion temperature (°C)	1290
	Air mass flow (kg/s)	200
	Fuel mass flow, 30% H_2, 70%CH_4 (kg/s)	4.3
	Lower heating value fuel (kJ/kg)	70,936
CGT-R	Isentropic efficiency, compressor (%)	85
	Isentropic efficiency, turbine (%)	88
	Pressure ratio of the cycle	6
	ΔT_{min} heat exchanger (°C)	20
LH_2 regas	Isentropic efficiency, cryogenic pump (%)	67
	ΔT_{min} heat exchanger (°C)	15

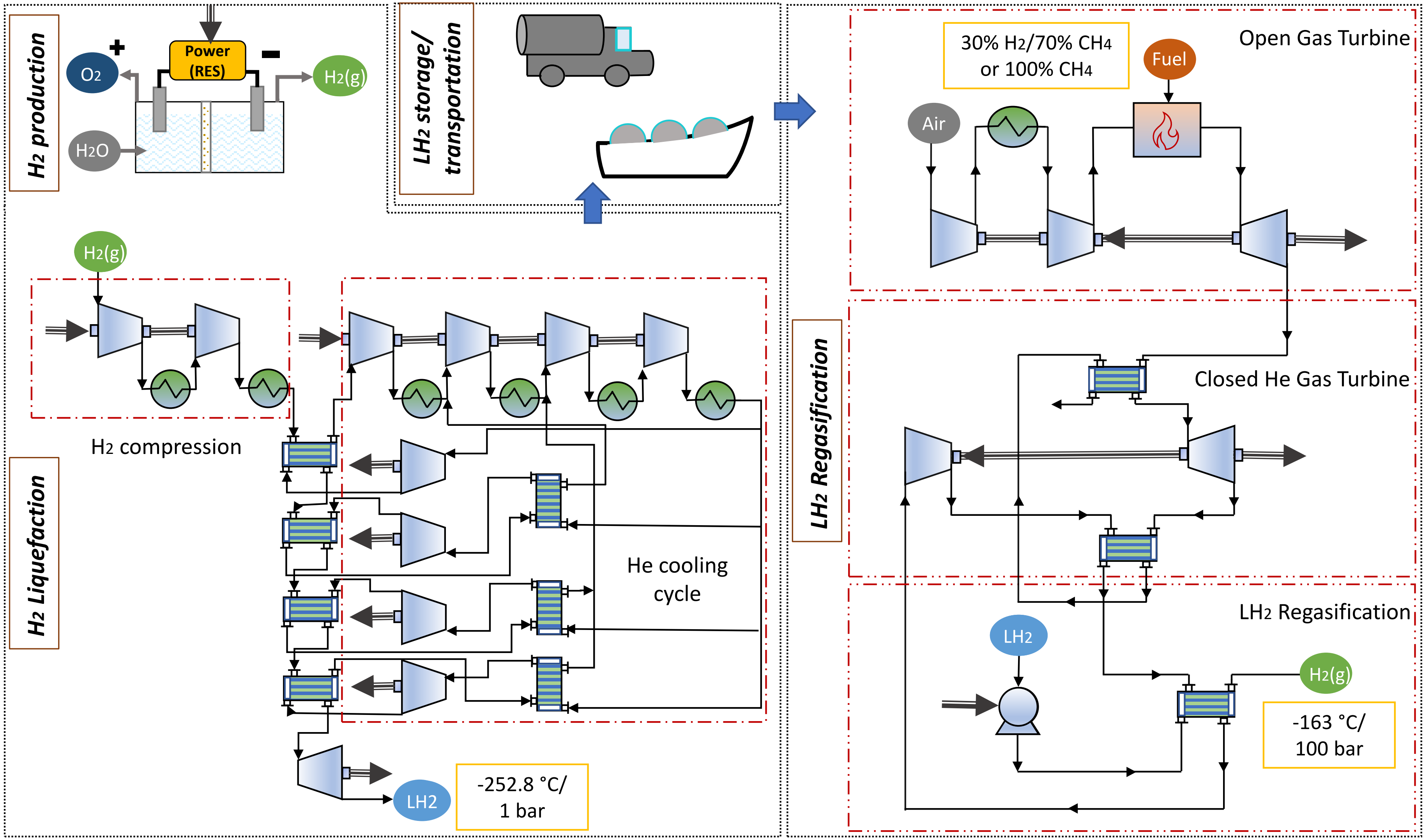


Figure 3.2. Description of the complete liquid hydrogen chain within a hydrogen economy

3.3. Ammonia

The system consisting of the production of liquid ammonia involves three phases. The production of green hydrogen via electrolysis and the further production of ammonia via the Haber-Bosch process, here electricity is “charged” to the system during the *charging phase*. Secondly, the *storage and transport phase* is when the ammonia is distributed for further use. Finally, a second *charging phase*, when the ammonia is reconverted to hydrogen via cracking of ammonia. The description of the ammonia chain within the hydrogen economy is presented in Figure 3.3.

After producing green hydrogen, it can be converted to ammonia via the Haber-Bosch process. The synthesis reaction is performed under high pressure of about 200-350 bar using a multi-promoted iron catalyst which runs at temperatures between 300-550 °C in a reactor with up to four catalyst beds [214]. The ammonia produced is separated, and the liquid can easily be stored or transported. After the ammonia reaches its destination, it can be reconverted to hydrogen via the process called cracking of ammonia. The reconversion reaction is endothermic; therefore, at least 15% of the ammonia has to be burned for the required heat of reaction. A furnace or catalytic combustor is needed for this purpose. The temperature required for the cracking depends on the catalyst. Therefore, there are currently many investigations on materials. Ni-based catalysts require temperatures from 800-1000 °C. After the reaction, the hydrogen stream still needs purification since only around 70% is hydrogen. The rest is mostly nitrogen and a smaller portion of unconverted ammonia (for conditions of 800 °C and 1 bar, the unconverted NH_3 is 0.025%) [215]. The cracking of ammonia configuration has been adapted from [215].

After the liquefaction of ammonia, 14% of the available energy is lost. During transportation over a distance of 8,000 km, about 1% of the energy is lost, and for the cracking of ammonia, 21% of the initial energy from the hydrogen is lost. Overall, the entire liquid ammonia chain remains with ca. 63% of the initial energy available from the green hydrogen produced [18].

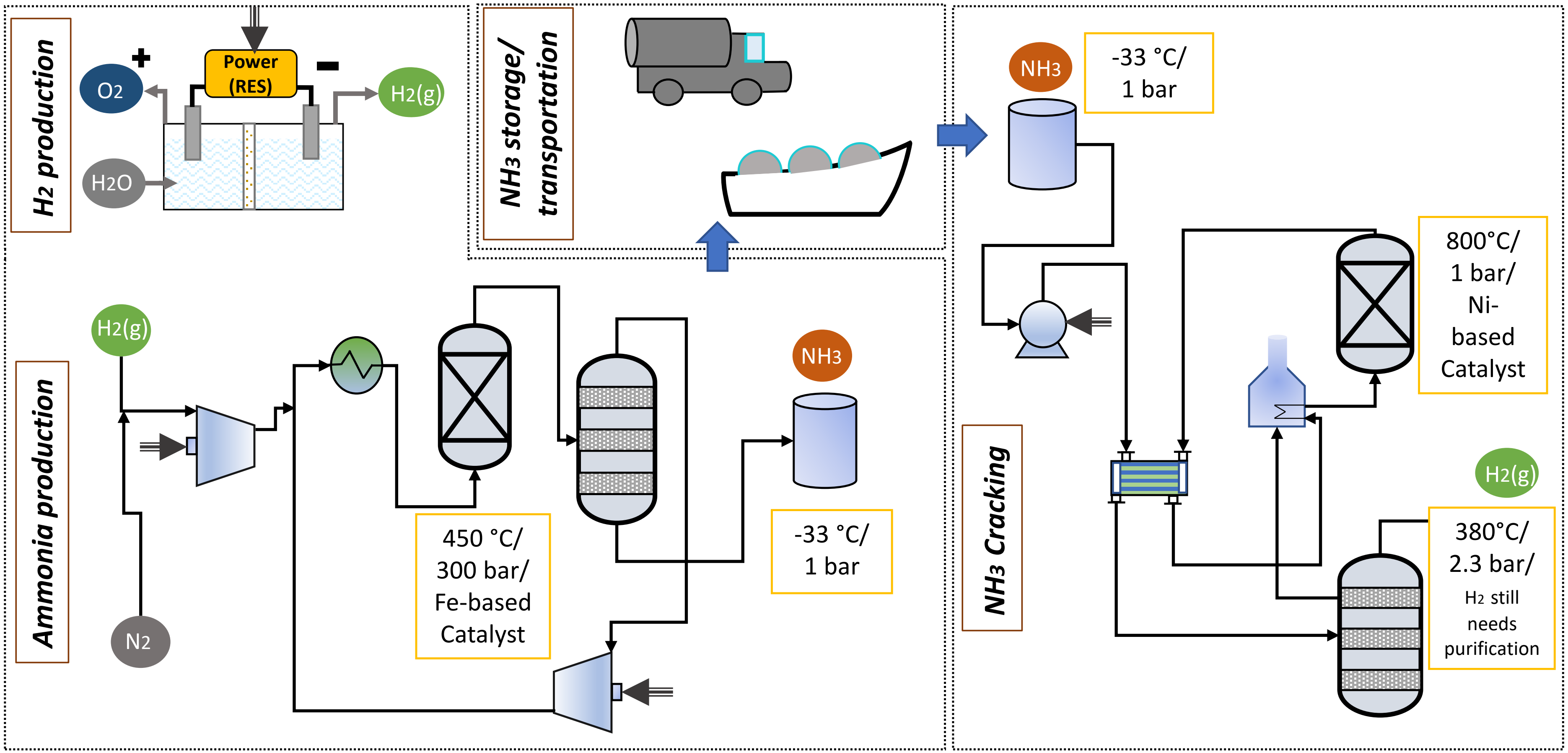


Figure 3.3. Description of the liquid ammonia chain within a hydrogen economy

3.4. Methanol

The system consisting of the production of methanol consists of three phases. The need for electricity to produce the green hydrogen via electrolysis and the further production of methanol via hydrogenation of CO_2. This will be called the *charging phase*. Secondly, the *storage and transport phase* is when the liquid methanol is distributed for further use. Finally, in a second *charging phase*, electricity is again required for the reconversion of methanol to hydrogen via the process of dehydrogenation of methanol. The complete methanol chain within a hydrogen economy is presented in Figure 3.4.

The traditional method for methanol production from syngas via hydrogenation of CO and CO_2 runs with a reverse water-gas shift reaction [184], [216]. Direct CO_2 hydrogenation is less utilized but is expected to be the motor of the methanol chain within the hydrogen economy. In this process, CO_2 and H_2 enter the system at an environmental temperature and 30 bar. Methanol and water are the products of this synthesis. The production conditions are under a pressure of 80 bar and a temperature of 230-250 °C [217]. The water is separated in a distillation column, and methanol is stored. Liquid methanol can be stored and transported until its destination, where it can be reconverted to hydrogen via methanol dehydrogenation. Hydrogen can again be synthesized from water and methanol at 20 bar and 250-260 °C and separated in a pressure swing adsorption unit. It is also possible to produce hydrogen from methanol at lower temperatures (< 100 °C) if formic acid is produced as an intermediate product. The enzyme oxidase can be used to partially oxidize CH_3OH with oxygen [218].

After the production of methanol, 5% of the available energy is lost. During transportation over a distance of 8,000 km, about 3% of the initially available energy is lost. For the dehydrogenation of methanol, up to 35% of the initial energy from the hydrogen is lost. Overall, the entire liquid methanol chain remains with 57-59% of the initial energy available from the green hydrogen produced [18].

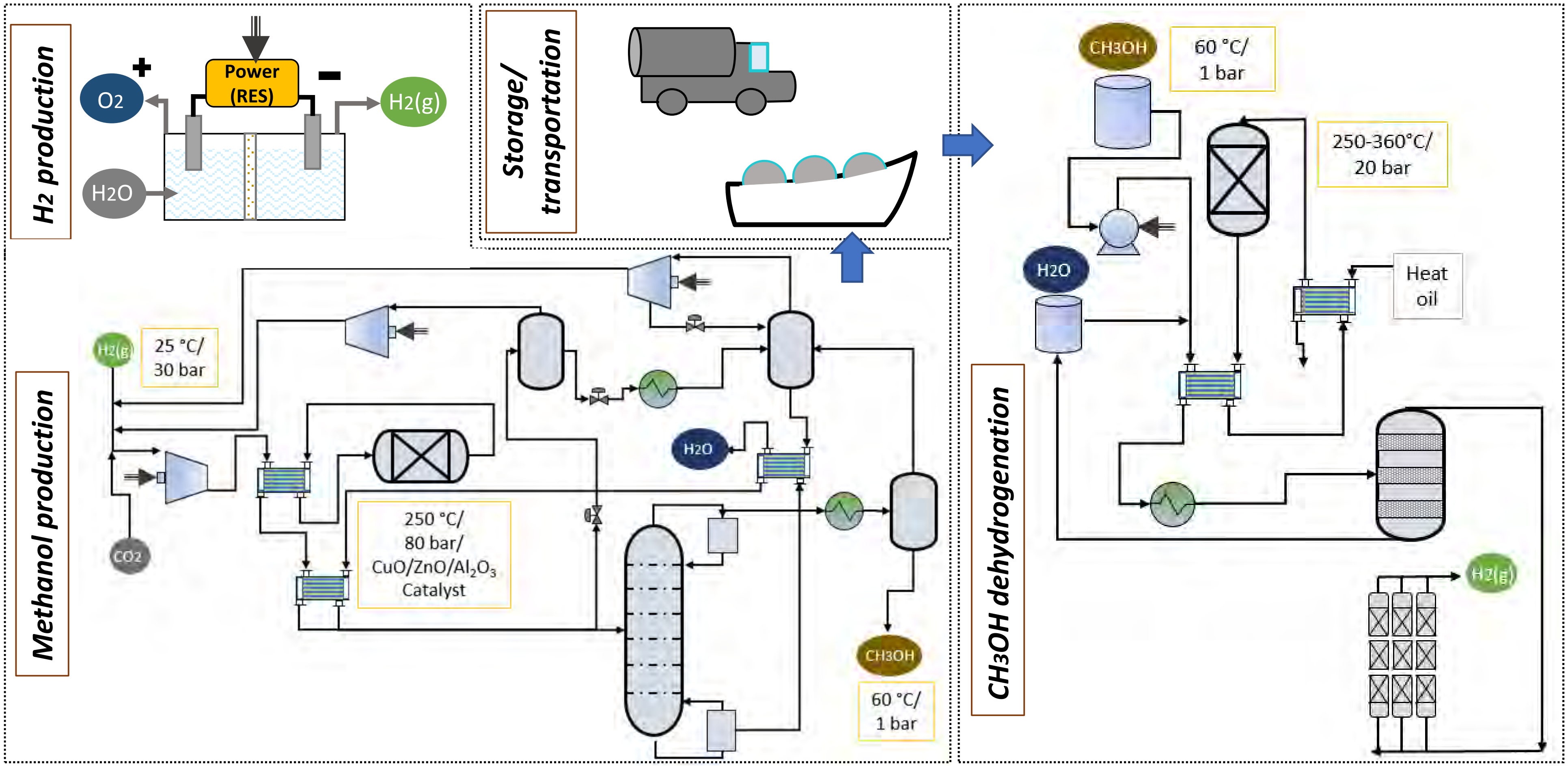


Figure 3.4. Description of the methanol chain within a hydrogen economy

Chapter 4. Methodology

The systematic approach followed in this thesis is divided into three phases, presented in Figure 4.1. First, an extensive literature review on energy storage technologies, non-dependent on geographical location, was performed in the *data collection phase*. Two technologies gained relevance after this first literature review phase, liquid air energy storage and hydrogen storage. A bibliographic study on the hydrogen economy showed political support favoring hydrogen-related technologies; therefore, further research focused only on the latter energy storage alternative. Every aspect of the hydrogen economy was reviewed, from production technologies to applications. The concept of Power-to-X has won visibility in the past five years and was addressed in this thesis. Also, the many hydrogen colors mentioned in the literature are explained. A research gap was identified for the liquid hydrogen chain, specifically for the regasification of the LH_2.

In the *data selection phase,* four pathways for Power-to-X were selected for comparison, and the criteria for this comparison were carefully chosen. Three multi criteria decision making tools were used. The weighting factors are calculated according to the Analytic Hierarchy Process (AHP) and the criteria of the author. Also, the state-of-the-art of the regasification of hydrogen was carefully studied to decide upon a configuration for the regasification of hydrogen.

Finally, in the *data analysis phase,* the liquid hydrogen chain (liquid hydrogen production and regasification) was evaluated with exergy-based methods and an economic analysis due to the lack of data for comparisons. The four concepts of PtX were assessed in a decision matrix developed for Germany as a case study. The data is qualitative and quantitative compared, and the advantages and disadvantages of the PtX are pointed out and discussed. The evaluation is divided into technical, thermodynamic, and economic perspectives.

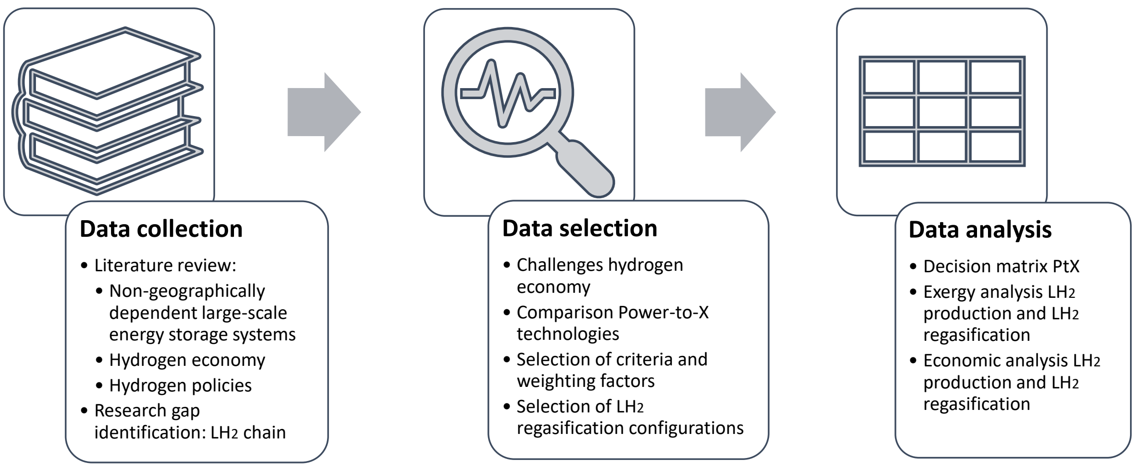


Figure 4.1. Methodology followed in this thesis

4.1. Exergy-based methods

The exergy analysis is based on the approach that considers the exergy of fuel and product according to [219], [220]. The exergy of fuel $\dot{E}_{F,k}$, exergy of product $\dot{E}_{P,k}$ and exergy destruction $\dot{E}_{D,k}$ are formulated at the component level, as shown in Eq. (4.1), and for the total system, as presented in Eq. (4.2). The exergy losses $\dot{E}_{L,tot}$ are calculated only for the overall system and the losses of the components are charged to the exergy destruction. The state point zero has been defined at a temperature of T_0 = 298.15 K and a pressure of p_0 = 1.01325 bar for each working fluid.

$$\dot{E}_{\mathrm{F,k}} = \dot{E}_{P,k} + \dot{E}_{D,k} \tag{4.1}$$

$$\dot{E}_{\mathrm{F,tot}} = \dot{E}_{P,tot} + \dot{E}_{D,tot} + \dot{E}_{L,tot} \tag{4.2}$$

The overall exergetic efficiency is calculated as shown in Eq. (4.3).

$$\varepsilon_{tot} = \frac{\dot{E}_{P,tot}}{\dot{E}_{F,tot}} \tag{4.3}$$

The liquid hydrogen chain partially works below the environmental temperature. Thus, the physical part of the exergy stream $\dot{E}_i^{Ph}$, is further split into its mechanical part $\dot{E}_i^{M}$ and thermal part $\dot{E}_i^{Th}$ according to the methodology in [221], as presented in Eq. (4.4).

$$\dot{E}_i = \dot{E}_i^{Ch} + \dot{E}_i^{Ph} = E_i^{Ch} + \dot{E}_i^{M} + \dot{E}_i^{Th} = \dot{m}_i \times (e_i^{Ch} + e_i^{M} + e_i^{Th}) \tag{4.4}$$

The values for the chemical exergies in this thesis correspond to the ones reported in [222]. The exergy destruction ratio was also calculated to identify the real inefficiencies of the system, as shown in Eq. (4.5).

$$y_{D,k} = \frac{\dot{E}_{D,k}}{\dot{E}_{F,tot}} \tag{4.5}$$

4.1.1. Green hydrogen production

The stack of the PEM electrolyzer considered for green hydrogen production is presented in Figure 4.2. The exergetic calculations for the electrolyzer were conducted manually. The electrolyzer unit consists of subsystems, such as the water treatment unit, the control cabinet, the power supply conversion from AC to DC, the drying system, and the compression unit. The exergetic calculations correspond only to the electrolyzer stack.

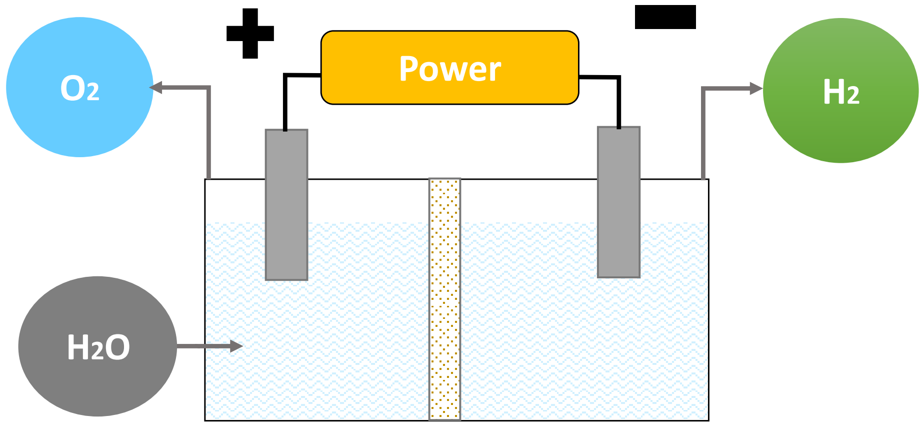


Figure 4.2. General green hydrogen production from PEM electrolysis

The electrolyzer splits the water into hydrogen and oxygen with the aid of electricity. Eq. (4.6) and Eq. (4.7) describe the definition of fuel and product for the PEM electrolyzer. In this case, oxygen can be considered part of the product, but it can also be a loss. The specific energy use of the electrolyzer of 5 kWh/ Nm^3 was considered [223].

$$\dot{E}_{F,Electrolyzer} = \dot{W}_{Electrolyzer} + \dot{E}_{H2O} \tag{4.6}$$

$$\dot{E}_{P,Electrolyzer} = \dot{E}_{H2} + \dot{E}_{O2} \tag{4.7}$$

4.1.2. Hydrogen liquefaction

The detailed flowsheet of hydrogen liquefaction according to [167] and modified as in [97] is presented in Figure 4.3, and the parameters of each stream are summarized in Table 4.1. The simulation of the liquefaction process was conducted with Aspen Plus® V10. For all hydrogen streams, the REFPROP equation of state was used. The Peng-Robinson equation of state was chosen for all other working fluids. The exergy-based analyses of the liquefaction process were conducted using the software EES® (Engineering Equation Solver V11.199-3D).

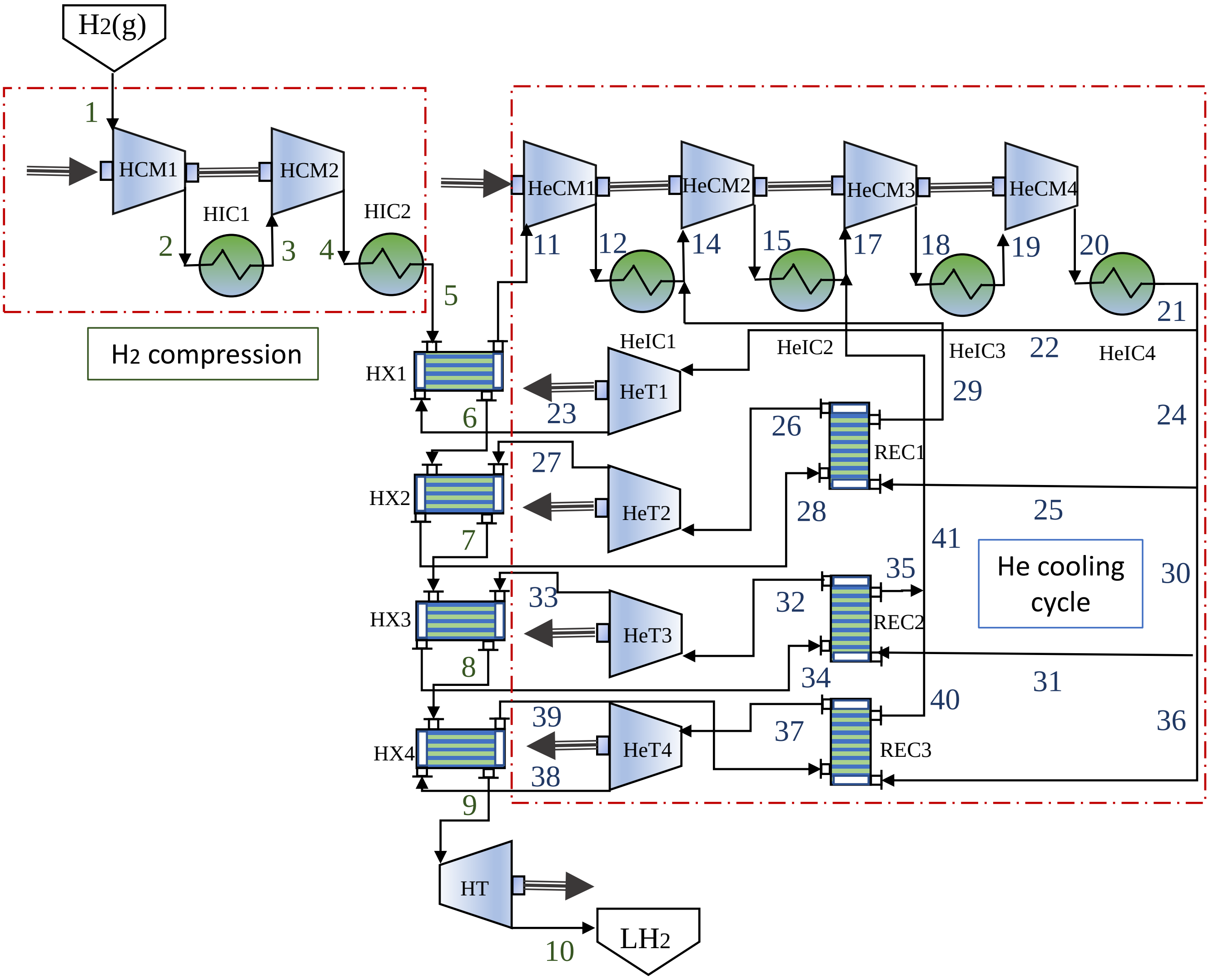


Figure 4.3. Detailed flowsheet of a hydrogen liquefaction system

Table 4.1. Detailed information about the liquid hydrogen configuration

Stream	**Working fluid**	$\dot{m}$ **(kg/s)**	***T*** **(K)**	***p*** **(bar)**	***h*** **(kJ/kg)**	e^{M}**(kJ/kg)**	e^{Th}**(kJ/kg)**
1	hydrogen	0.56	300	21.0	35.7	3742.0	<1
2	hydrogen	0.56	357	35.5	873.4	4398.2	755
3	hydrogen	0.56	300	35.1	42.1	4384.2	<1
4	hydrogen	0.56	60	60.5	922.5	5072.1	82
5	hydrogen	0.56	300	60.0	53.9	5062.3	<1
6	hydrogen	0.56	105	58.8	-2635.0	5036.1	1576.3
7	hydrogen	0.56	45	57.6	-3539.0	5010.1	4623.3
8	hydrogen	0.56	29	56.5	-3791.0	4984.1	6396.1
9	hydrogen	0.56	20	55.3	-3876.0	4959.2	7345.5
10	hydrogen	0.56	19	1.3	-3941.0	307.3	11819.1
11	helium	1.53	291	1.5	-37.5	251.2	<1
12	helium	1.53	444	3.8	757.5	824.2	141.2
13	helium	1.53	298	3.8	-0.3	817.3	0
14	helium	3.80	294	3.8	-20.1	817.3	<1
15	helium	3.80	403	7.5	544.5	1240.2	78.2
16	helium	3.80	298	7.4	-0.5	1233.3	0
17	helium	7.40	295	7.4	-18.2	1233.3	<1
18	helium	7.40	433	17.2	701.9	1754.2	123.6
19	helium	7.40	298	17.0	-1.1	1747.4	0
20	helium	7.40	483	40.5	959.7	2285.2	213.2
21	helium	7.40	298	40.0	-2.3	2277.5	0
22	helium	1.53	298	40.0	-2.3	2277.5	0
23	helium	1.53	103	1.6	-1014.0	267.3	633.6
24	helium	5.87	298	40.0	-2.3	2277.5	0
25	helium	2.27	298	40.0	-2.3	2277.5	0
26	helium	2.27	92	39.2	-1081.0	2265.6	760.5
27	helium	2.27	42	3.9	-1334.0	843.5	1716.4
28	helium	2.27	84	3.9	-1113.0	830.9	848.5
29	helium	2.27	292	3.8	-33.4	817.3	<1
30	helium	3.60	298	40.0	-2.3	2277.5	0
31	helium	2.29	298	40.0	-2.3	2277.5	0
32	helium	2.29	49	39.2	-1313.0	2265.6	1548.5
33	helium	2.29	27	7.7	-1414.0	1259.2	2326.6
34	helium	2.29	39	7.7	-1353.0	1259.2	1830.4
35	helium	2.29	290	7.4	-41.6	1233.3	<1
36	helium	1.31	298	40.0	-2.3	2277.5	0
37	helium	1.31	33	39.2	-1401.0	2265.6	2111.5
38	helium	1.31	18	7.7	-1464.0	1259.2	2937.4
39	helium	1.31	25	7.6	-1427.0	1246.8	2469.2
40	helium	1.31	293	7.4	-28.7	1233.4	<1
41	helium	3.60	291	7.4	-36.9	1233.3	<1

The exergy of fuel and product for the liquefaction system are defined by Eq. (4.8) and Eq. (4.9). The work considered for the continuous ortho-para hydrogen conversion ($\dot{W}_{o-p-conv}$) corresponds to the specific value of 0.59 kWh/kg_{H_2} [224], [161].

$$\dot{E}_{\mathrm{F,tot}} = \dot{E}_{H2} + (\dot{W}_{HCM1} + \dot{W}_{HCM2}) + (\dot{W}_{HeCM1} + \dot{W}_{HeCM2} + \dot{W}_{HeCM3} + \dot{W}_{HeCM4}) + \dot{W}_{o-p-conv} - (\dot{W}_{HeT1} + \dot{W}_{HeT2} + \dot{W}_{HeT3} + \dot{W}_{HeT4}) \tag{4.8}$$

$$\dot{E}_{P,\mathrm{tot}} = \dot{E}_{LH2} \tag{4.9}$$

The definition of exergy of the fuel and product for selected components of the liquid hydrogen configuration are shown in Table 4.2.

Table 4.2. Exergy of the fuel and product for selected components of the liquefaction system of the flowsheet given in Figure 4.3

Component	Exergy of the fuel	Exergy of the product
HCM1	$\dot{E}_{F,HCM1} = \dot{W}_{HCM1}$	$\dot{E}_{P,HCM1} = \dot{E}_2 - \dot{E}_1$
HIC	Dissipative component	
HX1	$\dot{E}_{F,HX1} = (\dot{E}_{23} - \dot{E}_{11}) + (\dot{E}_5^M - \dot{E}_6^M)$	$\dot{E}_{P,HX1} = \dot{E}_6^{Th} - \dot{E}_5^{Th}$
HX2	$\dot{E}_{F,HX2} = (\dot{E}_{27} - \dot{E}_{28}) + (\dot{E}_6^M - \dot{E}_7^M)$	$\dot{E}_{P,HX2} = \dot{E}_7^{Th} - \dot{E}_6^{Th}$
HeT1	$\dot{E}_{F,HeT1} = (\dot{E}_{22}^M - \dot{E}_{23}^M)$	$\dot{E}_{P,HeT1} = (\dot{E}_{23}^{Th} - \dot{E}_{22}^{Th}) + \dot{W}_{HeT1}$

4.1.3. Liquid hydrogen regasification

The hydrogen regasification cogeneration system shown in Figure 4.4 has been evaluated with exergy-based methods. The simulations of the regasification cogeneration systems were conducted using the EES® software V11.199-3D. The thermodynamic properties of all working fluids used in the open gas turbine system were calculated using the ideal gas model, while for helium (closed-cycle gas turbine system) and hydrogen (LH_2 regasification process), the thermodynamic properties of real gases were selected. The properties of normal gas hydrogen (75% orthohydrogen and 25% parahydrogen) included in EES® [225] were used. The detailed flowsheet of the regasification cogeneration system evaluated in this thesis is presented in Figure 4.4, and the parameters of the streams are summarized in Table 4.3. The physical exergy was not split for the streams of the OGT since they all operate at temperatures above the environment. Several configurations were evaluated. The configuration without the recuperator shown in Figure 4.5 will also be compared in the results.

The definition of exergy of the fuel and product for selected components of the liquid hydrogen regasification configuration are shown in Table 4.4.

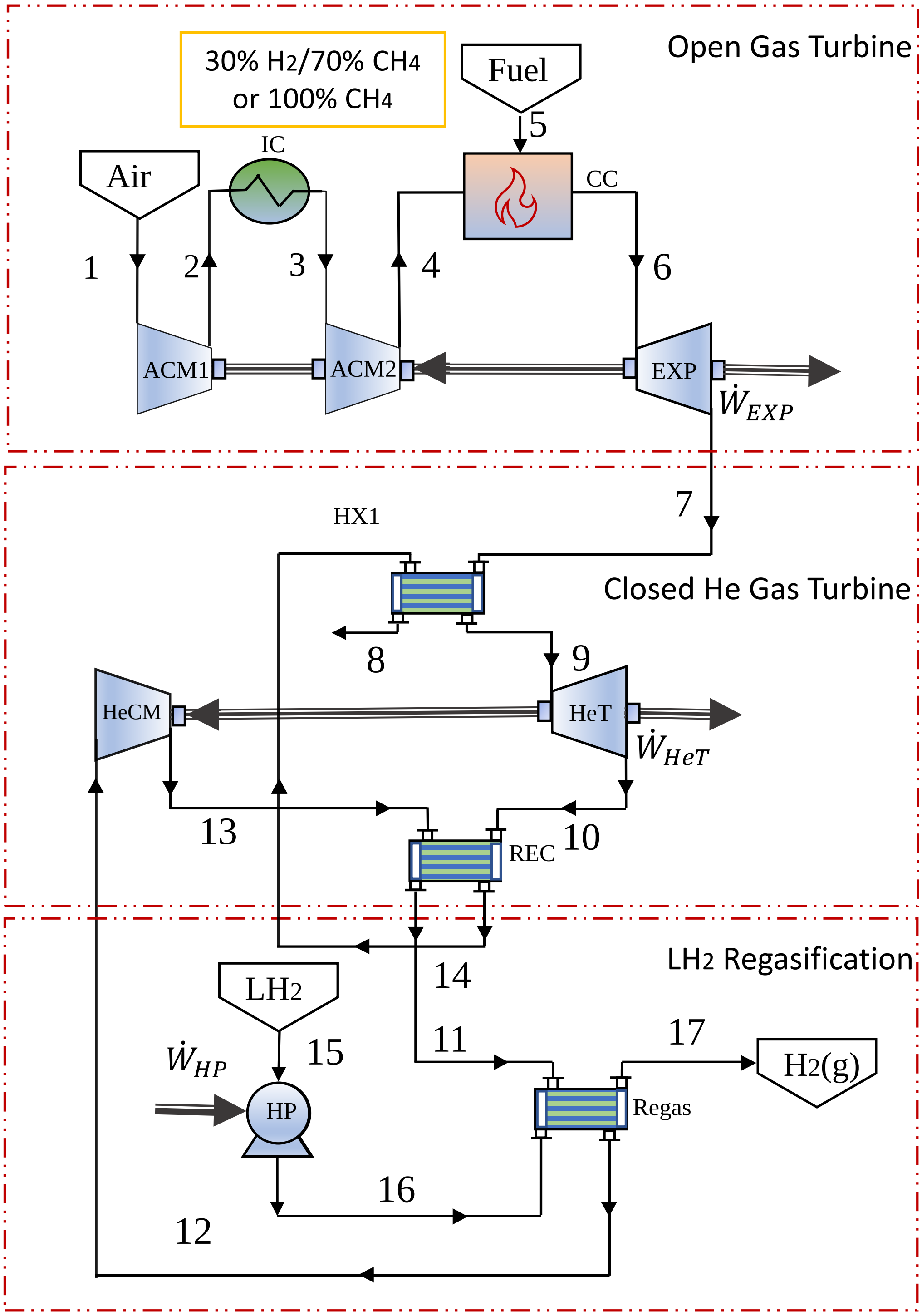


Figure 4.4. Detailed liquid hydrogen regasification cogeneration system with recuperator

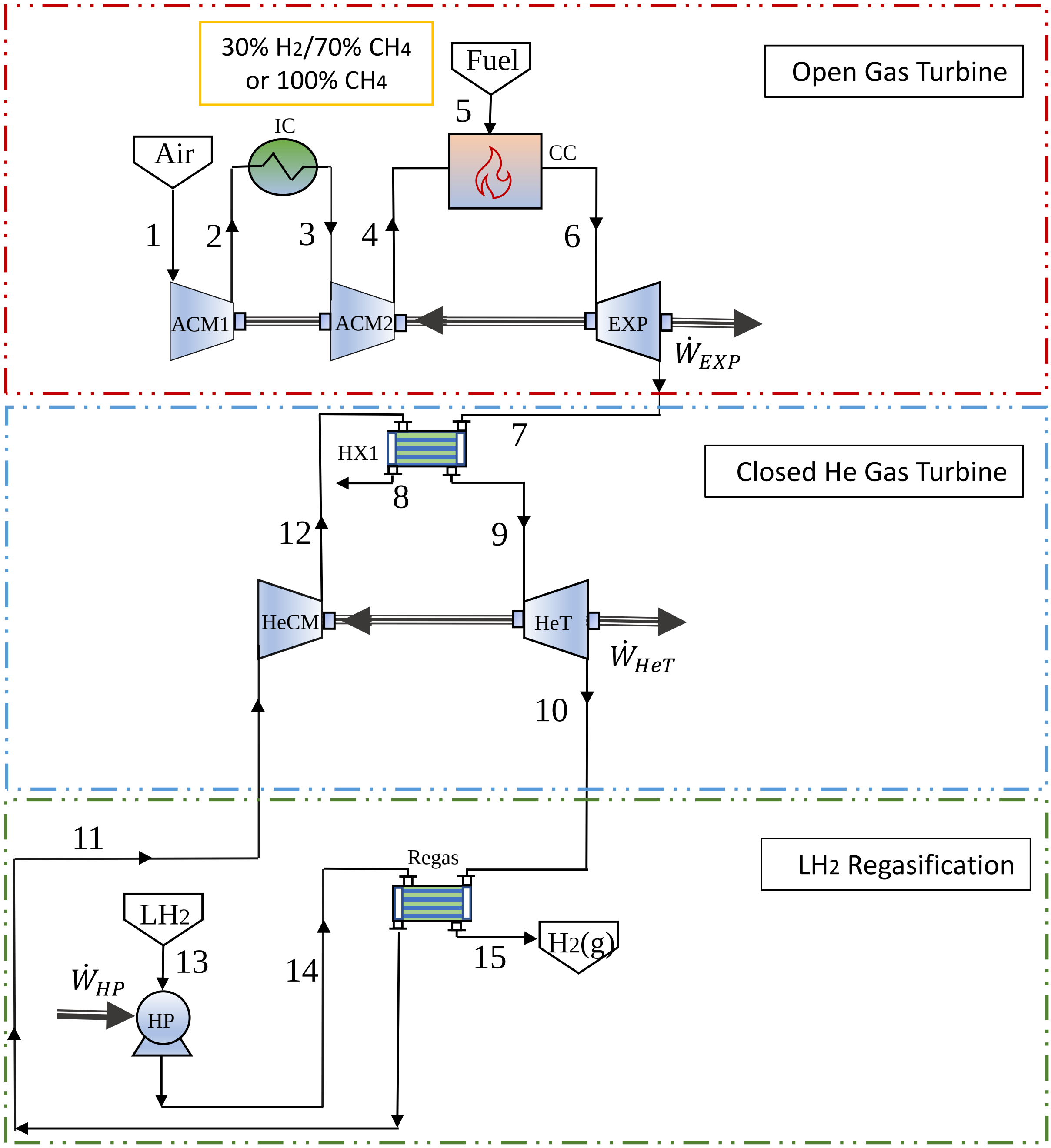


Figure 4.5. Detailed liquid hydrogen regasification cogeneration system without a recuperator

The exergetic efficiency of each subsystem is calculated as shown in Eq. (4.10), Eq. (4.11), and Eq. (4.12). The effect of the LH_2 regasification is included in the definition of energy and exergy efficiency.

$$\varepsilon_{OGT} = \frac{\dot{W}_{EXP} - \dot{W}_{ACM1} - \dot{W}_{ACM2} + (\dot{E}_7 - \dot{E}_8)}{\dot{E}_1 + \dot{E}_5} \tag{4.10}$$

$$\varepsilon_{CGT-R} = \frac{\dot{W}_{HeT} - \dot{W}_{HeCM} + \dot{E}_{17}^{Th}}{(\dot{E}_7 - \dot{E}_8) + (\dot{E}_{17}^{M} - \dot{E}_{16}^{M})} \tag{4.11}$$

$$\varepsilon_{Regasification} = \frac{\dot{E}_{12}^{Th} + (\dot{E}_{17}^{M} - \dot{E}_{15}^{M})}{(\dot{E}_{15}^{Th} - \dot{E}_{17}^{Th}) + (\dot{E}_{12}^{M} - \dot{E}_{11}^{M}) + \dot{E}_{11}^{Th} + \dot{E}_{12}^{Th} - \dot{W}_{HP}} \tag{4.12}$$

Table 4.3. Detailed information about the regasification of the liquid hydrogen cogeneration plant (see Figure 4.4 for stream number)

Stream	Material	$\dot{m}$ (kg/s)	T (°C)	p (bar)	h (kJ/kg)	e^{M} (kJ/kg)	e^{Th} (kJ/kg)	e^{Ph} (kJ/kg)
1	Air	200.0	15	1.0	288.5			0
2	Air	200.0	243	6.7	520.4			217.6
3	Air	200.0	113	6.5	387.3			167.3
4	Air	200.0	419	42.8	704.9			467.1
5	Fuel	4.3	15	45.0	-4441.2			767.4
6	Exhaust gas	204.3	1290	43.5	370.9			1274
7	Exhaust gas	204.3	423	1.0	-698.4			172.4
8	Exhaust gas	204.3	100	1.0	-1055.0			11.3
9	Helium	43.2	403	18.3	3523.1	1737.2	738.9	2476.1
10	Helium	43.2	99	3.1	1938.1	659.8	53.2	713.0
11	Helium	43.2	-144	3.0	673.8	647.6	378.8	1026.4
12	Helium	43.2	-227	2.8	244.7	608.9	1487.0	2095.9
13	Helium	43.2	-164	19.0	575.1	1761.1	527.3	2288.4
14	Helium	43.2	79	18.7	1839.2	1749.2	32.0	1781.2
15	LH_2	16.3	-253	1.0	-0.2	0	11453.0	11453.0
16	LH_2	16.3	-242	101.3	201.7	5545.2	5417.1	10962.3
17	Hydrogen	16.3	-163	99.3	1338.1	5520.1	1359.1	6879.2

Table 4.4. Exergy of fuel and product for selected components of the regasification system of the flowsheet shown in Figure 4.4

Component	Exergy of fuel	Exergy of product
ACM1	$\dot{E}_{F,ACM1} = \dot{W}_{ACM1}$	$\dot{E}_{P,ACM1} = \dot{E}_2 - \dot{E}_1$
IC	Dissipative component	
CC	$\dot{E}_{F,CC} = \dot{E}_5$	$\dot{E}_{P,CC} = \dot{E}_6 - \dot{E}_4$
EXP	$\dot{E}_{F,EXP} = \dot{E}_6 - \dot{E}_7$	$\dot{E}_{P,EXP} = \dot{W}_{EXP}$
HX1	$\dot{E}_{F,HX1} = \left(\dot{E}_7 - \dot{E}_8\right) + (\dot{E}_9^M - \dot{E}_{14}^M)$	$\dot{E}_{P,HX1} = \dot{E}_9^{Th} - \dot{E}_{14}^{Th}$
HeCM	$\dot{E}_{F,HeCM} = \dot{W}_{HeCM} + \dot{E}_{12}^{Th} - \dot{E}_{13}^{Th}$	$\dot{E}_{P,HeCM} = (\dot{E}_{13}^M - \dot{E}_{12}^M)$
HeT	$\dot{E}_{F,HeT} = (\dot{E}_9^M - \dot{E}_{10}^M)$	$\dot{E}_{P,HeT} = \dot{W}_{HeT} + \dot{E}_{10}^{Th} - \dot{E}_9^{Th}$
REC	$\dot{E}_{F,REC} = \left(\dot{E}_{13}^{Th} + \dot{E}_{10}^{Th}\right) + (\dot{E}_{11}^M - \dot{E}_{10}^M) + (\dot{E}_{14}^M - \dot{E}_{13}^M)$	$\dot{E}_{P,REC} = \left(\dot{E}_{14}^{Th} + \dot{E}_{11}^{Th}\right)$
Regas	$\dot{E}_{F,Regas} = \left(\dot{E}_{11}^{Th} + \dot{E}_{16}^{Th}\right) + \left(\dot{E}_{17}^M - \dot{E}_{16}^M\right) + (\dot{E}_{12}^M - \dot{E}_{11}^M)$	$\dot{E}_{P,Regas} = \left(\dot{E}_{12}^{Th} + \dot{E}_{17}^{Th}\right)$
HP	$\dot{E}_{F,HP} = \dot{W}_{HP} + (\dot{E}_{14}^{Th} - \dot{E}_{15}^{Th})$	$\dot{E}_{P,HP} = \dot{E}_{15}^M - \dot{E}_{14}^M$
Overall system	$\dot{E}_{F,tot} = \left(\dot{E}_1 + \dot{E}_5\right) + \left(\dot{E}_{15}^{Th} - \dot{E}_{17}^{Th}\right)$	$\dot{E}_{P,tot} = \dot{W}_{Net,tot} + \left(\dot{E}_{17}^M - \dot{E}_{15}^M\right)$

4.2. Economic analysis

The economic analysis followed the Total Revenue Requirement (TRR) method, according to [226], [227]. The levelized TRR accounts for the levelized carrying charges (CC), operation and maintenance costs (OMC), and fuel costs (FC), as shown in Eq. (4.13). First, the total capital investment (TCI) was calculated. The economic (such as taxes, insurance, depreciation), financial (such as return on equity or/and debt, interests), and market inputs, such as inflation, were considered for the detailed cost calculation of the regasification plant. Then the TRR was calculated, and the levelized cost of the product was obtained. The FC and OMC are going to be paid during the plant operation phase, while the CC are part of the construction phase.

$$TRR_{Lev} = CC_{Lev} + FC_{Lev} + OMC_{Lev} \tag{4.13}$$

The detailed lifetime and exact moments when each cost or material will be acquired are presented in Figure 4.6.

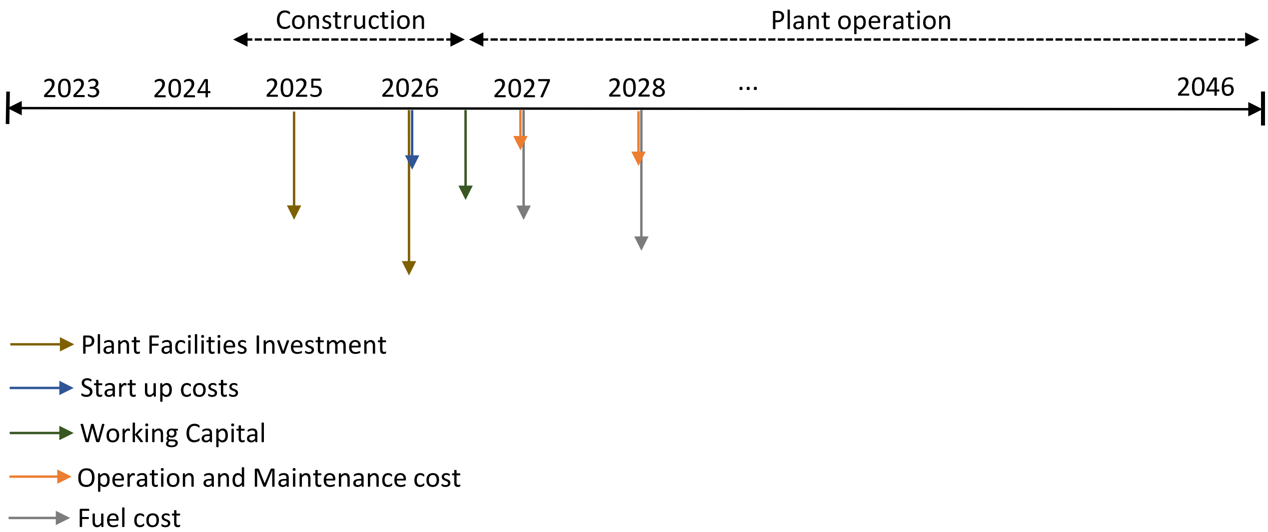


Figure 4.6. The detailed lifetime of the liquid hydrogen plant and regasification plant

The carrying charges can be calculated based on the Bare Module Costs (BMC) or Purchased Equipment Costs (PEC) of the system components and the total capital investment with the aid of the capital recovery factor (CRF) as in Eq. (4.14).

$$CC_{Lev} = TCI \times CRF \tag{4.14}$$

And the CRF can be calculated as in Eq. (4.15).

$$CRF = \frac{i_{eff}(1 + i_{eff})^n}{(1 + i_{eff})^n - 1} \tag{4.15}$$

The i_{eff} is the average annual effective discount rate to calculate the time value of money and n the plant's economic life. The breakdown of the fixed capital investment (FCI) in direct and indirect costs and the TCI is summarized in Table 4.5

To estimate the PEC, different methods have been used, such as obtaining the costs from the cost estimating charts [228] [229], equations [230], and past purchase orders [231] [232] adjusted to US$$_{2021}$ with the chemical engineering cost indexes ($CEPCI_{2021}$ = 708 [233]) as shown in Eq. (4.16).

$$Cost_{Ref.\ year} = \frac{CEPCI_{Ref.\ year}}{CEPCI_{known\ cost\ year}} \times Cost_{known} \tag{4.16}$$

Table 4.5. Breakdown of the fixed capital investment costs and total capital investment

Direct costs (DC)		**Assumptions (%)**
Onsite costs	Purchased Equipment Cost (PEC)	
	Purchased equipment installation	33 of PEC
	Piping	35 of PEC
	Instrumentation and controls	12 of PEC
	Electrical equipment and materials	13 of PEC
Offsite costs	Land	0 of PEC
	Civil work	21 of PEC
	Service facilities	35 of PEC
Indirect costs (IC)		
	Engineering and supervision	8 of DC
	Construction costs	15 of DC
	Contingencies	10-15 of FCI
Other possible costs		
	Startup costs	8 of FCI
	Working capital	12 of TCI
	Allowance for funds	
	Cost of licensing	

Also, in some cases, the equipment size was adjusted to the PEC of a similar component with a different size using the characteristic variable of a component x and the scaling exponent α, as described in Eq. (4.17). For turbomachines, the design variable is typically the power, and for heat exchangers, the area. The scaling factor depends on the size and the type (e.g., the PEC of heat exchangers increases linearly but not for turbomachinery). The average value of 0.6 can be used when the scaling factor is unknown.

$$PEC_{new} = \left(\frac{x_{new}}{x_{known}}\right)^{\alpha} \times PEC_{known} \tag{4.17}$$

Finally, the parameters such as the design, pressure, temperature, and material can also be adjusted with the help of factors, as presented in Eq. (4.18).

$$PEC_{new} = PEC_{known} f_d f_p f_T f_m \tag{4.18}$$

Similarly, the BMC are calculated (mostly with charts and corresponding equation) based on the PEC cost with the most simple design, material, lowest possible pressure, and temperature, including the bare module factor f_{BM}, as shown in Eq. (4.19). [234] developed diagrams with the factors to adjust the PEC value known and not adding the other onsite costs considered in Table 4.5.

$$BMC = PEC_{known} f_d f_p f_T f_m f_{BM} \tag{4.19}$$

When the FCI was calculated with the PEC, the additional costs of installation, instrument, and control were calculated. However, when the FCI was calculated with BMC, all the extra costs were already included with the f_{BMC}.

The fuel costs can be levelized to the entire lifetime of the plant and escalated with the aid of parameters that account for the effect of the nominal escalation rate of the fuel costs (r_{FC}>inflation rate) and the constant escalation levelization factor ($CELF$). As shown in Eq.(4.20), Eq.(4.21) and Eq.(4.22).

$$FC_{Lev} = FC_{initial} \times CELF \tag{4.20}$$

where,

$$CELF = \frac{k_{FC}(1 - k_{FC}^n)}{1 - k_{FC}} \times CRF \tag{4.21}$$

And

$$k_{FC} = \frac{1 + r_{FC}}{1 + i_{eff}} \tag{4.22}$$

The OMC were divided into fixed and variable, and assumed as a percentage of the FCI, and the levelization of the costs is calculated as the levelized fuel costs, but instead of a constant nominal escalation of the fuel costs, a constant nominal escalation of the OMC (r_{OMC}) is used.

4.2.1. Green hydrogen production

For green hydrogen production, the cost of the electrolyzer stacks and the balance of the plant (BoP) are considered. The BoP includes the subsystems necessary to make the stack work (e.g., water treatment to deionized quality, control cabinet, power supply conversion from AC to DC, drying system, and safety valves) [96]. The cost of the stack varies from 1000-1500 US$/kW [235]. The efficiency of the electrolyzer is more accurate compared with the amount of electricity required to produce 1 kg (or 1 Nm^3). This value greatly varies from 3.7 kWh/Nm^3 [236] to 6.8 kWh/Nm^3 [223]. The assumptions used for the calculation are summarized in Table 4.6.

Table 4.6. Assumptions for the economic analysis of the green H_2 production *[96], [235]*

Parameter	**Value**
Stack (US$/kW)	1000
BoP (US$/kW)	300
Compression to 30 bar (US$/kW)	200
Specific energy use (kWh/Nm^3)	5
Electricity price (US$/MWh) [237]	110
Operation time (h)	7446
Lifetime (years)	10

4.2.2. Hydrogen liquefaction

The lifetime of the electrolyzer assumed is ten years, and the lifetime of the liquefaction plant is 20 years. Therefore, all the electrolyzers must be changed after ten years. The price of the electrolyzer in the second round of investment will be lower according to the predictions of IRENA [95]. The green hydrogen price in the next 20 years is difficult to calculate due to possible governmental incentives; therefore, the value is assumed to be average. The OMC were assumed as a percentage of the FCI, 4%. The contingencies were assumed to be 10 % BMC since it is a new process with proven technologies. Engineering and supervision are 10% of the BMC, and the construction is 15 % of BMC.

The carrying charges are calculated based on the total capital investment costs. The estimation of the PEC and the BMC are based on [231], cost estimating charts [228], [229] and cost estimating equation in [230]. A detailed estimation of some of the equations for the component costs used in this section is given in Table 4.8. The materials of the component significantly influence the capital cost, and the low temperatures involved in the LH_2 chain make the total PEC more expensive. For components working under temperatures higher than -29°C, carbon steel is usually used. The components with a working fluid temperature lower than -29°C use stainless steel since carbon steel loses ductility and becomes fragile [238]. Materials with high strength and high ductility should be used for components using LH_2, such as aluminum and most of its alloys [239]. The cost functions used to estimate the costs are summarized in Table 4.8 (for LH_2) and Table 4.11 (for regasification of hydrogen).

The estimation of the costs of the compressors depends on the power requirements. The costs for the compressors are adopted from cost graphs from [229] when the power is within the range (100 kW < $\dot{W}$ < 6,000 kW), for the other compressors, the equation in Table 4.8 was used. The temperature and pressure factors depend on the respective temperature and pressure levels. They were adopted from [240]. The material factor used was 4.4, according to Table 4.7 in [231]. The BMC is adopted from [234]. The turbines were calculated according to [228]. All the assumptions made in the economic analyses for the green hydrogen liquefaction are summarized in Table 4.9.

Table 4.7. Typical material factors for equipment cost estimation

Material	f_M
Carbon steel	1.0
Aluminum	1.3
Stainless steel (low grade)	2.4
Nickel	4.4

The overall heat transfer coefficient U depends on the heat exchanger type and the phase of the streams inside the considered heat exchanger and is assumed based on data in [164]. The heat exchangers that are used for hydrogen use aluminum brazed plate-fin heat exchangers. All other heat exchangers are constructed as shell and tube type made of either high-grade stainless steel or carbon steel, depending on their operating temperature. The cost estimation of the aluminum plate heat exchangers for hydrogen is based on data from [231] calculated based on the effect of the size of the equipment on the cost. The scaling factor for the aluminum plate heat exchangers is 0.68. The pressure, temperature, and material factors were also obtained from [231]. The bare module factors were adopted from [234]. The cost estimation for the shell and tube heat exchangers is based on the equations in Table 4.8

The heat exchanger area can be calculated with Eq. (4.23).

$$\dot{Q} = U \times a \times \Delta T_{ln} \tag{4.23}$$

Table 4.8. Purchased Equipment Cost functions used for the liquefaction of hydrogen

Component type	**Design variable**	**Cost function**	**Source**
Compressor	Power ($\dot{W}$)- in Horse Power	$PEC = 7900(\dot{W})^{0.62}$	[241]
Gas turbine	Power ($\dot{W}$)	The cost data is adopted from cost graphs with the respective material, pressure, and bare module factors.	[228]
Heat exchanger (counter-flow)	Heat exchanger area, A (m^2)	$PEC = 130(\frac{Area}{0.093})^{0.78}$	[228]

Table 4.9. Assumptions for the economic analysis of the liquid hydrogen production

Parameter	**Value**
Effective interest rate (%)	10
First electrolyzer investment cost (US$/$kW_{el}$)	1000
Second electrolyzer investment cost (US$/$kW_{el}$)	700
Specific energy use PEM electrolyzer (kWh/ Nm^3)	5
Operation time (h/a)	7446
Average general inflation rate (%)	5
Average electricity escalation rate (%)	4
Average nominal escalation rate (%)	5
Contingencies (%of BMC)	15
Engineering and Supervision (%of BMC)	15
Construction (%of BMC)	15
Annual OMC (%of FCI)	4
Lifetime liquefier (years)	20
Lifetime electrolyzer (years)	10
Base electricity price (US$/MWh)	110

4.2.3. Liquid hydrogen regasification

The assumptions made in the economic analysis for the liquid hydrogen regasification are summarized in Table 4.10. The cost equations used for calculating the component costs are found in Table 4.11.

Table 4.10. Assumptions for the economic analysis of the liquid hydrogen regasification

Parameter	**Value**
Average general inflation rate (%)	5
Average nominal escalation rate (%)	5= inflation (real escalation rate =0)
Average nominal escalation NG (%)	4
Average annual effective discount rate (%)	10
Operation time (h/a)	7446
Average equivalent capacity factor (%)	85
NG (US$/kWh)	0.085
Annual OMC (%of FCI)	4
Plant economic lifetime (years)	20
Plant economic lifetime (years) for tax purposes	15
Common equity (%)	50
Debt (%)	50
Required annual return on common equity (%)	10
Required annual return on debt (%)	8
Average property tax rate and insurance	2
Depreciation method for tax purposes	MACRS
Depreciation method for internal purposes	Straight line
Tax (%) [242]	30

Table 4.11. Purchased Equipment Cost functions for the regasification of hydrogen

Component type	Design variable	Cost function	Source
Compressor	Power ($\dot{W}$)	$PEC = 91562(\frac{\dot{W}}{445})^{0.67}$	[228]
Gas turbine	Power ($\dot{W}$)	$PEC = \left(-98.328\ln\left(\dot{W}\right) + 1318.5\right)\dot{W}$	[243]
Heat exchanger (counter-flow)	Heat exchanger area (m^2)	$PEC = 130(\frac{Area}{0.093})^{0.78}$	[228]
Pump	Capacity ($\dot{W}$)	$PEC = 442(W)^{0.71}1.41(1 + (\frac{0.2}{1-\eta}))$	[229]
Combustion chamber	$\dot{m}$ (kg/s), p (bar), T (K)	$PEC = (\frac{46.08\,\dot{m}}{0.995 - \frac{p_{in}}{p_{out}}})(1 + \exp(0.018T - 26.4))$	[228]

For the regasification of hydrogen, the system's profitability was assessed since the regasification plant will most likely be constructed in European ports, unlike the liquefaction of hydrogen, which will be constructed in the country where the green hydrogen is produced.

The profitability of the project can be assessed with static or dynamic methods. The static methods contemplated here are the Average Rate of Return (ARR) and the Payback (PB) Period. The two dynamic methods correspond to the Net Present Value (NPV) and the Internal Rate of Return (IRR) [226].

The Average Rate of Return (ARR) calculates the average arithmetic net cash flow (ANCF) without considering the time value of money, which could lead to misleading the profitability of the project. It is calculated as the rate between the average annual profit and the total initial investment, including the working capital.

The Payback Period (PB) does not consider the time value of money and favors projects with long lifetimes. It can be calculated with two methods, Method 1 as in Eq. (4.24).

$$\sum_{z=0}^{\tau_{PB}} Y_z = 0 \tag{4.24}$$

or with Method 2, as shown in Eq. (4.25).

$$\tau_{PB} = \frac{TDI}{ANCF} \tag{4.25}$$

The Net Present Value (NPV) uses discounted cash flows. If the calculated *NPV* is negative, the project cannot meet the rate of return, *i*, assumed for the project. The *NPV* is calculated as shown in Eq.(4.26). The *NPV* method implies that every year, the net cash flow is reinvested somewhere else at an annual rate of return equal to the assumed rate of return for the project under analysis.

$$NPV_0 = \sum_{z=0}^{n} Y_z \,(1+i)^{-z} \tag{4.26}$$

The Internal Rate of Return (IRR) calculates the actual interest rate, *i**, that makes the net present value of the project zero. The IRR represents the interest rate from the time-dependent balances to make the project's final investment zero at the end of the lifetime, as shown in Eq.(4.27).

$$NP_0 = \sum_{z=0}^{n} Y_z \,(1+i^*)^{-z} = 0 \tag{4.27}$$

4.3. Decision matrix

Four Power-to-X alternatives are compared with multi criteria decision making tools: Power-to-Hydrogen gas, Power-to-Liquid hydrogen, Power-to-Ammonia, and Power-to-Methanol. Fifteen criteria are evaluated for each alternative, as shown in Table 4.12. The decision matrix was analyzed with three MCDM tools and two weighting factor methods, as shown in Table 4.13. The MCDM methods are the Weighting Sum Method (WSM), Technique for Order Preference by Similarity to Ideal Solution (TOPSIS) and the Weighted Aggregated Sum Product Assessment (WASPAS). Additionally, the weighting factors have been selected for each parameter and are calculated according to the Analytic Hierarchy Process (AHP) and weighting factors subjective to the criteria of the author.

Table 4.12. Criteria evaluated for the decision matrix

Number	Criteria	
1	Cost of production	Levelized cost of production
2		Specific energy use
3	Emissions	CO_2
4		NOx
5	Water use	
6	Technological Readiness Level	
7	Infrastructure	
8	Support by government	
9	Social acceptance	
10	Storage	Temperature
11		Pressure
12	Transportation	
13	Safety	Explosion limits in air
14		Toxicity
15	Heating Value	

Table 4.13. Multi criteria decision making methods and weighting factors used to assess the four PtX alternatives

Case	Multi criteria decision matrix	Weighting factor method
1	Weighting Sum Method	Analytic Hierarchy Process
2	Weighting Sum Method	Subjective
3	Technique for Order Preference by Similarity to Ideal Solution	Subjective
4	Technique for Order Preference by Similarity to Ideal Solution	Analytic Hierarchy Process
5	Weighted Aggregated Sum Product Assessment	Subjective
6	Weighted Aggregated Sum Product Assessment	Analytic Hierarchy Process

4.3.1. Case 1: Weighting Sum Model / Weighting factor: Analytic Hierarchy Process

This decision matrix is based on the Weighting Sum Model (WSM) approach. The value of 0 is assigned to the base case, Power-to-Hydrogen gas. The weighting factors have been selected for each parameter and are calculated according to the Analytic Hierarchy Process (AHP) [244]. The value of 3 is given to significantly better parameters than hydrogen gas (base case), and the value of -3 means substantially worse than hydrogen gas. The value 0 means it is equally compared to the base case. For storage conditions, the parameters are divided into temperature and pressure, and safety is divided into toxicity and explosion limits in air. The parameters that were assigned with the highest importance in the weighting system are the levelized cost, the CO_2 emissions, and infrastructure.

First, a hierarchical structure was developed with a goal at the top level, the attributes/criteria at the second level, and the alternatives at the third level.

- Top level: The goal is to find the best PtX solution for the study case, Germany.
- Second level: The selected criteria for comparison are the levelized cost of production (LCO), specific energy use, CO_2 emissions, NOx emissions, water use, Technology Readiness Level, infrastructure, governmental support, social acceptance, storage temperature, storage pressure, transportation, explosion limits in air, toxicity, and heating value.
- Third level: The evaluated alternatives are Power-to-Hydrogen gas, Power-to-Liquid hydrogen, Power-to-Ammonia, and Power-to-Methanol.

Second, a pair-wise comparison matrix was filled. The equation row element/column will be calculated according to the relative importance presented in Table 4.14. The numbers of the intermediate results of the pair-wise comparison evaluation are presented in Table 4.15.

Third, a normalized pair-wise comparison matrix was calculated. The intermediate results are presented in Table 4.16.

Fourth, the weighting factors were calculated. The weighting factor of each criterion is calculated, as shown in Table 4.17, as the average value of all the normalized pair-wise comparison matrix.

Finally, the consistency of the weighting factors was determined. Each non-normalized value is multiplied by the criteria weight to find the weighted sum value of each parameter. This value is divided by the weighting factor (w), as shown in the last column of Table 4.18.

Table 4.14. Relative importance of criteria with respect to the goal

Scale of relative importance	
1	Equal importance
3	Moderate importance
5	Strong importance
7	Very strong importance
9	Extreme importance
2,4,6,8	Intermediate values
1/3, 1/5, 1/7, 1/9	Values for inverse comparison

Table 4.15. Pair-wise comparison matrix of the criteria analyzed for the four technologies considered in this thesis

Criteria	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Levelized cost of production	1	3	2	3	3	3	3	2	2	3	3	3	4	4	3
Specific energy use	1/3	1	1/5	2	2	2	2	2	2	3	3	3	2	2	2
Emissions (CO_2)	1/2	5	1	3	3	3	3	3	3	3	3	3	3	3	3
Emissions (NOx)	1/3	1/2	1/3	1	1/2	1/3	1/4	1/2	1/3	1/2	1/2	1/4	1	1/2	1/2
Water use	1/3	1/2	1/3	2	1	1/5	1/4	1/2	1/3	1/3	1/3	1/4	2	1/2	1/2
Technology readiness level	1/3	1/2	1/3	3	5	1	1	2	2	5	5	1	5	5	2
Infrastructure	1/3	1/2	1/3	4	4	1	1	1/2	1/2	4	4	1	4	4	4
Governmental support	1/2	1/2	1/3	2	2	1/2	2	1	2	2	2	2	5	5	2
Acceptance (social)	1/2	1/2	1/3	3	3	1/2	2	1/2	1	4	4	1/2	5	5	5
Storage temperature	1/3	1/3	1/3	2	3	1/5	1/4	1/2	1/4	1	1	1/3	2	2	2
Storage pressure	1/3	1/3	1/3	2	3	1/5	1/4	1/2	1/4	1	1	1/3	2	2	2
Transportation	1/3	1/3	1/3	4	4	1	1	1/2	2	3	3	1	4	4	4
Safety (Explosion limits in air)	1/4	1/2	1/3	1	1/2	1/5	1/4	1/5	1/5	1/2	1/2	1/4	1	1/2	1/2
Safety (Toxicity)	1/4	1/2	1/3	2	2	1/5	1/4	1/5	1/5	1/2	1/2	1/4	2	1	1/2
Heating Value	1/3	1/2	1/3	2	2	1/2	1/4	1/2	1/5	1/2	1/2	1/4	2	2	1
Sum	6.0	14.5	7.2	36.0	38.0	13.8	16.7	14.4	16.3	31.3	31.3	16.4	44.0	40.5	32.0

Table 4.16. Normalized pair-wise comparison matrix of the criteria analyzed for the four technologies considered in this thesis

Criteria	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Levelized cost of production	0.167	0.207	0.278	0.083	0.079	0.217	0.179	0.139	0.123	0.096	0.096	0.183	0.091	0.099	0.094
Specific energy use	0.056	0.069	0.028	0.056	0.053	0.145	0.119	0.139	0.123	0.096	0.096	0.183	0.045	0.049	0.063
Emissions (CO_2)	0.083	0.345	0.139	0.083	0.079	0.217	0.179	0.208	0.184	0.096	0.096	0.183	0.068	0.074	0.094
Emissions (NOx)	0.056	0.034	0.046	0.028	0.013	0.024	0.015	0.035	0.020	0.016	0.016	0.015	0.023	0.012	0.016
Water use	0.056	0.034	0.046	0.056	0.026	0.014	0.015	0.035	0.020	0.011	0.011	0.015	0.045	0.012	0.016
Technology readiness level	0.056	0.034	0.046	0.083	0.132	0.072	0.060	0.139	0.123	0.160	0.160	0.061	0.114	0.123	0.063
Infrastructure	0.056	0.034	0.046	0.111	0.105	0.072	0.060	0.035	0.031	0.128	0.128	0.061	0.091	0.099	0.125
Governmental support	0.083	0.034	0.046	0.056	0.053	0.036	0.119	0.069	0.123	0.064	0.064	0.122	0.114	0.123	0.063
Acceptance (social)	0.083	0.034	0.046	0.083	0.079	0.036	0.119	0.035	0.061	0.128	0.128	0.030	0.114	0.123	0.156
Storage temperature	0.056	0.023	0.046	0.056	0.079	0.014	0.015	0.035	0.015	0.032	0.032	0.020	0.045	0.049	0.063
Storage pressure	0.056	0.023	0.046	0.056	0.079	0.014	0.015	0.035	0.015	0.032	0.032	0.020	0.045	0.049	0.063
Transportation	0.056	0.023	0.046	0.111	0.105	0.072	0.060	0.035	0.123	0.096	0.096	0.061	0.091	0.099	0.125
Safety (Explosion limits in air)	0.042	0.034	0.046	0.028	0.013	0.014	0.015	0.014	0.012	0.016	0.016	0.015	0.023	0.012	0.016
Safety (Toxicity)	0.042	0.034	0.046	0.056	0.053	0.014	0.015	0.014	0.012	0.016	0.016	0.015	0.045	0.025	0.016
Heating Value	0.056	0.034	0.046	0.056	0.053	0.036	0.015	0.035	0.012	0.016	0.016	0.015	0.045	0.049	0.031

Table 4.17. Weighting factors of the criteria analyzed for the four technologies considered in this thesis

Criteria	**Criteria weights**
Levelized cost of production	0.142
Specific energy use	0.088
Emissions (CO_2)	0.142
Emissions (NOx)	0.025
Water use	0.028
Technology readiness level	0.095
Infrastructure	0.079
Governmental support	0.078
Acceptance (social)	0.084
Storage temperature	0.039
Storage pressure	0.039
Transportation	0.080
Safety (Explosion limits in air)	0.021
Safety (Toxicity)	0.028
Heating Value	0.034

Table 4.18. Consistency of the calculated weighting factors of the criteria analyzed for the four technologies considered in this thesis

Criteria	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**WSV/*w***
Levelized cost of production	0.142	0.264	0.284	0.074	0.083	0.285	0.236	0.156	0.168	0.116	0.116	0.240	0.084	0.112	0.103	17.342
Specific energy use	0.047	0.088	0.028	0.049	0.055	0.190	0.157	0.156	0.168	0.116	0.116	0.240	0.042	0.056	0.069	17.954
Emissions (CO_2)	0.071	0.439	0.142	0.074	0.083	0.285	0.236	0.234	0.251	0.116	0.116	0.240	0.063	0.084	0.103	17.881
Emissions (NOx)	0.047	0.044	0.047	0.025	0.014	0.032	0.020	0.039	0.028	0.019	0.019	0.020	0.021	0.014	0.017	16.493
Water use	0.047	0.044	0.047	0.049	0.028	0.019	0.020	0.039	0.028	0.013	0.013	0.020	0.042	0.014	0.017	15.993
Technology readiness level	0.047	0.044	0.047	0.074	0.138	0.095	0.079	0.156	0.168	0.193	0.193	0.080	0.106	0.140	0.069	17.141
Infrastructure	0.047	0.044	0.047	0.098	0.110	0.095	0.079	0.039	0.042	0.155	0.155	0.080	0.084	0.112	0.138	16.826
Governmental support	0.071	0.044	0.047	0.049	0.055	0.047	0.157	0.078	0.168	0.077	0.077	0.160	0.106	0.140	0.069	17.261
Acceptance (social)	0.071	0.044	0.047	0.074	0.083	0.047	0.157	0.039	0.084	0.155	0.155	0.040	0.106	0.140	0.172	16.859
Storage temperature	0.047	0.029	0.047	0.049	0.083	0.019	0.020	0.039	0.021	0.039	0.039	0.027	0.042	0.056	0.069	16.161
Storage pressure	0.047	0.029	0.047	0.049	0.083	0.019	0.020	0.039	0.021	0.039	0.039	0.027	0.042	0.056	0.069	16.161
Transportation	0.047	0.029	0.047	0.098	0.110	0.095	0.079	0.039	0.168	0.116	0.116	0.080	0.084	0.112	0.138	17.011
Safety (Explosion limits in air)	0.035	0.044	0.047	0.025	0.014	0.019	0.020	0.016	0.017	0.019	0.019	0.020	0.021	0.014	0.017	16.433
Safety (Toxicity)	0.035	0.044	0.047	0.049	0.055	0.019	0.020	0.016	0.017	0.019	0.019	0.020	0.042	0.028	0.017	16.036
Heating Value	0.047	0.044	0.047	0.049	0.055	0.047	0.020	0.039	0.017	0.019	0.019	0.020	0.042	0.056	0.034	16.194

The average weighted sum value ratio (A.W.S.V), as calculated in Eq. (4.28), is used to estimate the consistency of the weighting factors with the aid of the consistency Index (C.I.), as in Eq. (4.29) and the consistency ratio (C.R.), as shown in Eq. (4.30).

$$\mathrm{A.W.S.V} = Average\left(\frac{Weighted\ sum\ value}{Weighting\ factor}\right) \tag{4.28}$$

$$C.I. = \frac{(\mathrm{A.W.S.V} - No.criteria)}{No.criteria - 1} \tag{4.29}$$

According to the Random Index (R.I.) for 15 criteria, the R.I. corresponds to 1.59 [245].

$$C.R. = \frac{C.I.}{R.I._{15}} \tag{4.30}$$

4.3.2. Case 2: Weighting Sum Model / Weighting factor: subjective

This decision matrix is also based on the WSM approach, like in Case 1. The weighting factors have been selected for each parameter according to the criteria of the author. The weighting factors for each criterion, as shown in Table 4.19.

Table 4.19. Subjective weighting factors for each criterion

Criteria		**Weight factor (%)**
Cost of production	Levelized cost of production	12
	Specific energy use	5
Emissions	CO_2	8
	NOx	5
Water use		6
Technological Readiness Level		6
Infrastructure		10
Support by government		6
Social acceptance		6
Storage	Temperature	5
	Pressure	5
Transportation		10
Safety	Explosion limits in air	5
	Toxicity	6
Heating Value		5
Total		100

4.3.3. Case 3: Technique for Order Preference by Similarity to Ideal Solution/ Weighting factor: subjective

The Technique for Order Preference by Similarity to Ideal Solution (TOPSIS) method is based on Euclidean distance between two points. There cannot be negative numbers; therefore, another matrix has been created only with positive numbers, as presented in Table 4.20. The methodology was followed according to [246].

Table 4.20. Alternative score to categorize the criteria for each case

Alternatives score	Low	Below average	Average	Good	Excellent
points	1	2	3	4	5

First, the matrix is normalized with Eq. (4.31)

$$\overline{x_{ij}} = \frac{x_{ij}}{\sqrt{\sum_{j=1}^{n} x_{ij}^2}} \tag{4.31}$$

Second, the weighted normalized matrix is calculated, and the ideal best and worst are calculated:

- Ideal Best, V_j^+
  The ideal best means the highest value of the weighted normalized decision matrix; according to the score points assigned, the highest value represents a better alternative than the ones with lower values.
- Ideal Worst, V_j^-

For some criteria, the ideal best corresponds to the maximum value, e.g., technology readiness level, but in some cases, the ideal best represents the minimum value, e.g., cost of production.

Third, the best alternative is chosen by calculating the performance value as shown in Eq. (4.32), Eq.(4.33), and Eq.(4.34) :

- Euclidean distance from the ideal best, S_i^+

$$S_i^+ = \sqrt{\sum_{j=1}^{m} (V_{ij} - V_j^+)^2} \tag{4.32}$$

- Euclidean distance from the ideal worst, S_i^-

$$S_i^- = \sqrt{\sum_{j=1}^{m} (V_{ij} - V_j^-)^2} \tag{4.33}$$

- Calculation of performance score, P_i

$$P_i = \frac{S_i^-}{S_i^+ + S_i^-} \tag{4.34}$$

4.3.4. *Case 4: Technique for Order Preference by Similarity to Ideal Solution/ Weighting factor: Analytic Hierarchy Process*

In this case, the same decision matrix calculated in Case 3 is used for the Technique for Order Preference by Similarity to Ideal Solution method and the weighting factor method presented in Case 1.

4.3.5. *Case 5: Weighted Aggregated Sum Product Assessment/ Weighting factor: subjective*

The Weighted Aggregated Sum Product Assessment (WASPAS) method is the combination of Combination of Weighting Sum Model and Weighting Product Model (WPM). The same normalized decision matrix as the one used in Case 3 was applied in Case 5. The methodology was followed according to [247].

First, for the WSM, the weight factor, w_j, subjective to the criteria of the author, is applied as in Case 2.

Second, the performance value, A_i, is calculated, as presented in Eq. (4.35).

$$A_i(WSM) = \sum_{j=1}^{n} x_{ij} w_j \tag{4.35}$$

The preference score from the WSM is obtained, Eq. (4.36).

$$Q_i^1 = A_i(WSM) \tag{4.36}$$

Now, for the weighting product model (WPM), a second performance value is calculated, as shown in Eq. (4.37).

$$A_i(WPM) = \prod_{j=1}^{n} {x_{ij}}^{w_j} \tag{4.37}$$

The preference score from the WPM is obtained, Eq.(4.38).

$$Q_i^2 = A_i(WPM) \tag{4.38}$$

Finally, the joint generalized criterion of WASPA with λ = 0.5 is calculated and shown in Eq.(4.39) .

$$Q_i = \lambda Q_i^1 + (1 - \lambda) Q_i^2 \tag{4.39}$$

4.3.6. Case 6: Weighted Aggregated Sum Product Assessment/ Weighting factor: Analytic Hierarchy Process

This case uses the same matrix applied in Case 5, and the weighting factor method followed in Case 1 is used in this case.

Chapter 5. Results and Discussion

This chapter presents all the results and analyses of the calculations and information gathered for the Power-to-X comparisons. It is divided into the exergy and economic analyses for the liquid hydrogen chain, followed by the classification of the hydrogen colors and the comparison of the four systems: Power-to-Hydrogen gas, Power-to-Liquid hydrogen, Power-to-Ammonia, and Power-to-Methanol. Finally, the best Power-to-X solution for a study case in Germany is analyzed with six scenarios applying multi criteria decision making tools.

5.1. Green liquid hydrogen chain

For green hydrogen production, a PEM electrolyzer was considered, and an exergy analysis was conducted. The total exergy of each stream of the PEM electrolyzer was calculated, the results are shown in Table 5.1, and an exergy analysis was conducted. The PEM electrolyzer considered for this analysis with an energy use of 5 kWh/Nm^3_{H2} has an exergy efficiency of 60%, taking into account hydrogen as a product of the system and oxygen as a loss. If oxygen was considered a product of the system, the exergetic efficiency would increase by only one percentage point. This small increase is because the standard chemical exergy of hydrogen is much higher than that of oxygen, which affects the overall efficiency. The dependency of the exergetic efficiency of the electrolyzer with the specific energy use of the process is presented in Figure 5.1. The specific energy use of the electrolysis process is often presented as a critical parameter of the electrolyzer.

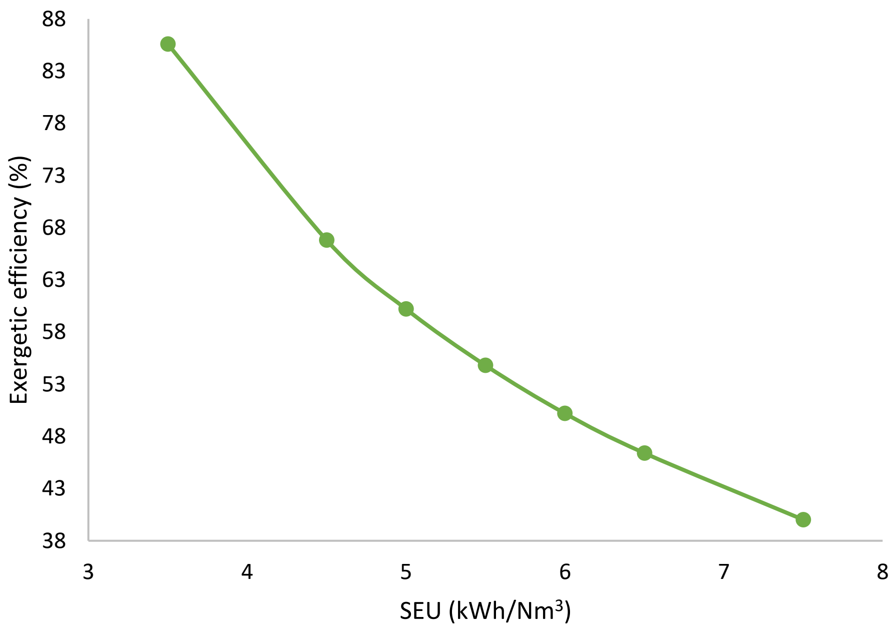


Figure 5.1. Relation of the exergetic efficiency of the stack with the specific energy use (SEU)

Table 5.1. Exergy calculations of the electrolysis process

Substance	mol	$\dot{E}_i^{Ph}$(kW)	$\dot{E}_i^{Ch}$(kW)	$\dot{E}_i^{tot}$ (kW)
H_2O	1.0	1662.4	247.5	1909.9
H_2	1.0	1605.0	64927.5	66532.5
O_2	0.5	802.8	545.9	1348.6

Table 5.2. Exergy balance of the electrolysis process

SEU (kWh/Nm^3)	$\dot{E}_F$ (MW)	$\dot{E}_P$(MW)	$\dot{E}_D$(MW)	$\dot{E}_L$(MW)	ε (%)
3.5	78.1	66.9	10.2	1.0	85.6
4.5	101.0	67.0	32.0	1.0	66.8
5	111.0	66.9	43.2	1.0	60.2
5.5	122.0	66.9	54.1	1.0	54.8
6	133.0	67.0	65.0	1.0	50.2
6.5	144.0	67.0	76.0	1.0	46.4
7.5	166.0	66.9	98.1	1.0	40.0

Table 5.3. Economic analysis of the electrolyzer

Parameter	Value
Hydrogen production (kg/h)	1800
Capital recovery factor electrolyzer	0.16
Stack specific cost (US$/kW)	1000
Stack total cost (US$)	143 million
Balance of Plant specific cost (US$/kW)	300
Balance of Plant cost (US$)	42 million
Compression specific cost (US$/kW)	200
Compression cost (US$)	28 million
Total cost (US$)	214 million
Specific energy use electrolyzer (kWh/kg)*	55.5

*1 kg_{H2} → 11.3 $Nm^3{}_{H2}$ (for gas at environmental pressure and 0 °C)

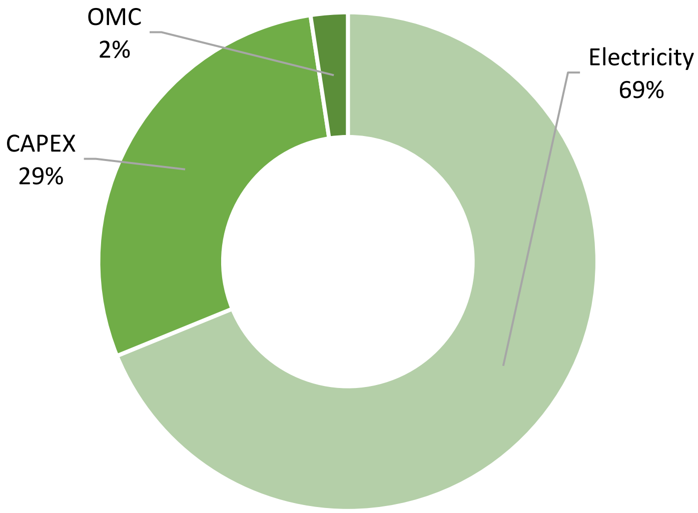


Figure 5.2. Distribution of the total cost of green hydrogen from PEM electrolyzer

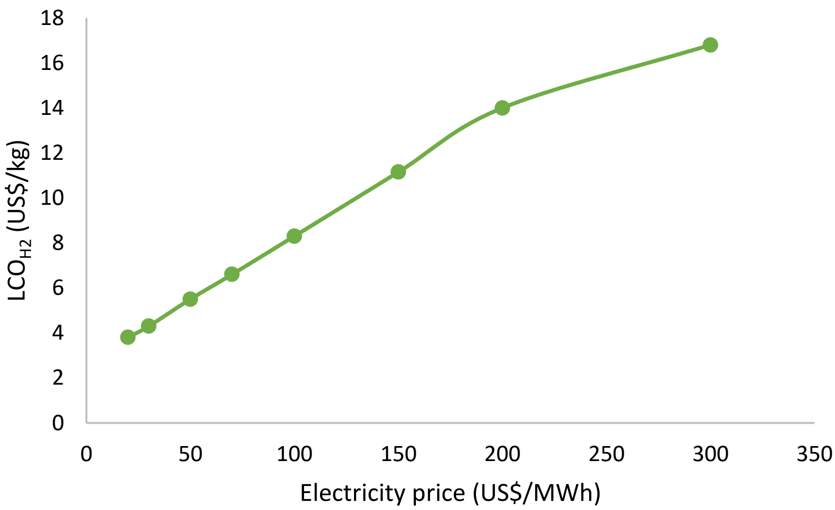


Figure 5.3. Sensitivity analysis of the levelized cost of green hydrogen from PEM electrolyzer in relation to the electricity price

As mentioned in the methodology, only the electrolyzer stack is taken into account. The rest of the components of the electrolyzer are not considered in this calculation. The high exergy destruction of the electrolyzer is primarily due to the chemical reactions that occur in the cathode and anode. The exergy balances for seven SEU are presented in Table 5.2.

The main part of the cost of green hydrogen corresponds to the electricity required to run the electrolyzer. The levelized cost of green hydrogen of 8.8 US$/kg was calculated (for an electricity price of 110 US$/MWh) and split into the 2% of operation and maintenance costs, around 30% of the cost corresponds to the stack, and the rest to the electricity price, as presented in Figure 5.2. The assumptions used for the calculation are summarized in Table 4.6. A total investment of about 215 million US$ for the stacks and a levelized TRR of 119 million US$ was calculated.

A sensitivity analysis of the cost of green hydrogen depending on the electricity price is shown in Figure 5.3. The electricity price in Spain for the month of April 2023 [237], for example, would lead to a LCO_{H2} of 5.3 US$/$kg_{H2}$, while in Italy would be 10.9 US$/$kg_{H2}$ and 8.3 in Germany US$/$kg_{H2}$. More results of the analysis are presented in Table 5.3.

The further liquefaction of green hydrogen was simulated and evaluated with exergy-based methods. The results were compared with different values reported in the literature. The exergetic efficiency, ε, and SEU indicators were calculated; the values correspond to 42.1% and 8.06 kWh/kg_{H2}, respectively. For the liquefaction of 0.55 kg/s hydrogen, a total of 15 MW is required.

The distribution of the total exergy destruction per component group of the liquefaction plant is presented in Figure 5.4. The liquefier had a total exergy destruction of 9.3 MW. The exergy destruction in the compressors represents the highest source of exergy destruction within the liquefier, followed by the expanders. The turbomachinery account for 62% of the total exergy destruction within the entire system. The system operates with three helium recuperators, with a total heat duty of 7.3 MW. These recuperators are in charge of cooling the working fluid from environmental to cryogenic temperature, therefore, the high exergy destruction.

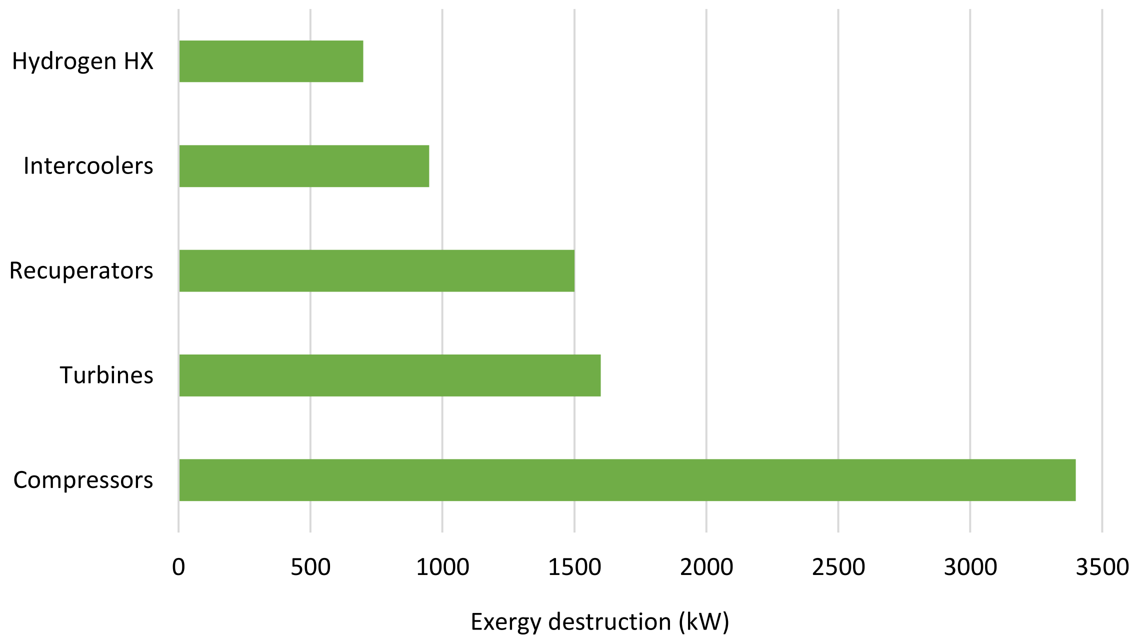


Figure 5.4. Exergy destruction for each component group of the liquefaction of hydrogen

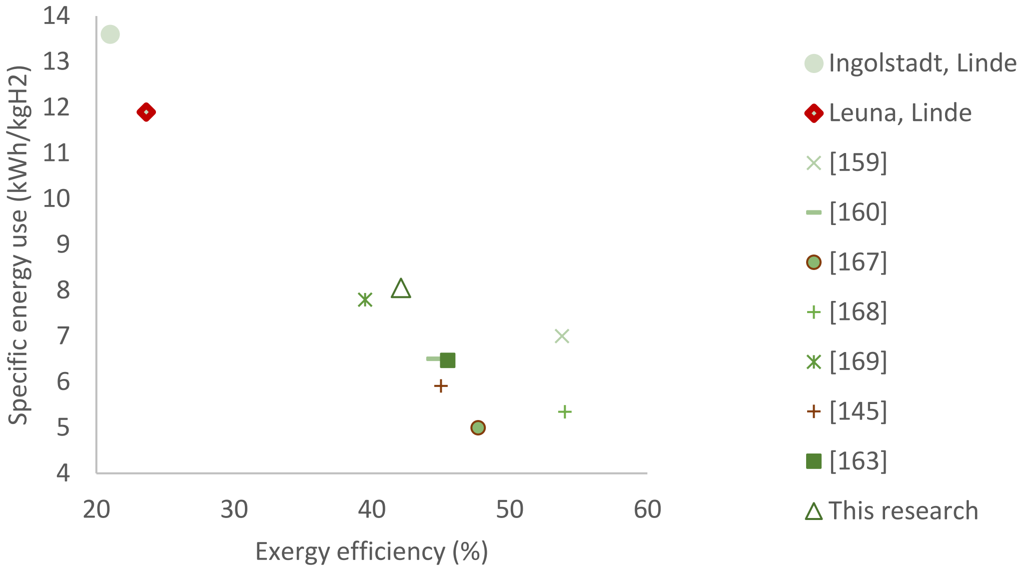


Figure 5.5. Exergetic efficiency of liquefaction processes in relation to the specific energy use of the simulated system (based on Table 2.9)

The results were compared with the literature, as summarized in Figure 5.5. The analysis showed that the energy consumption of the liquefaction system simulated in this thesis was greater than the majority of the reference values found in the literature. In contrast, all theoretical values were approximately half of those observed in the only two real plants considered for this comparison. Real operation has significantly lower exergetic efficiencies and higher energy demands.

The BMC of each component of the liquefier is shown in Figure 5.6. The compressors were identified as the primary contributor to the BMC of the liquefaction system, accounting for approximately 68% of the total capital cost. Following the compressors, the recuperators also played a significant role in the cost due to their requirement for special materials capable of withstanding cryogenic temperatures. These materials are considerably more expensive compared to heat exchangers used in other applications. Given the high volatility of hydrogen, the liquefaction process requires large compressors made from robust alloys. Relevant parameters from the simulation for the estimation of costs of the turbomachinery are presented in Table 5.4, and for the heat exchangers in Table 5.6. The total capital investment for the entire liquefaction plant was determined to be lower than that of the PEM electrolyzer. This is because the assumed lifespan of the electrolyzer is ten years, whereas the liquefaction plant is designed to last for twenty years, which is the timeframe considered in the economic analysis. Consequently, all the electrolyzers must be replaced with new units after ten years of operation.

A specific levelized cost for the liquefaction of hydrogen of 1.66 US$/kg was calculated. The total revenue requirement distribution is presented in Figure 5.7. The fuel cost represents around 67% since the cost of the green hydrogen is taken into account, the OMC represent 8% of the TRR, and the carrying charges the 25%. All other values from the economic analysis are presented in Table 5.5 and in Table 5.7.

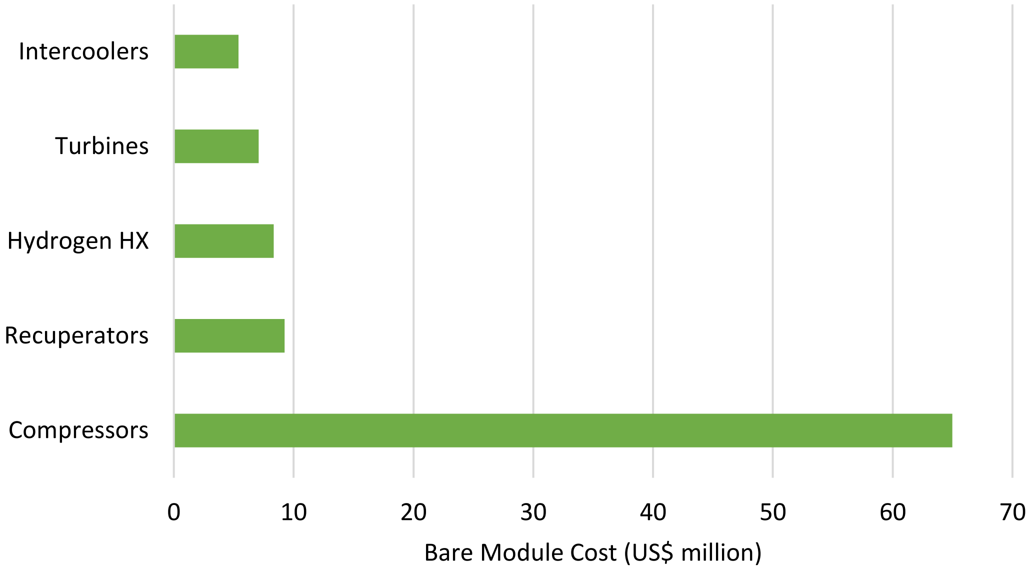


Figure 5.6. Bare Module Cost of the components of the liquefier

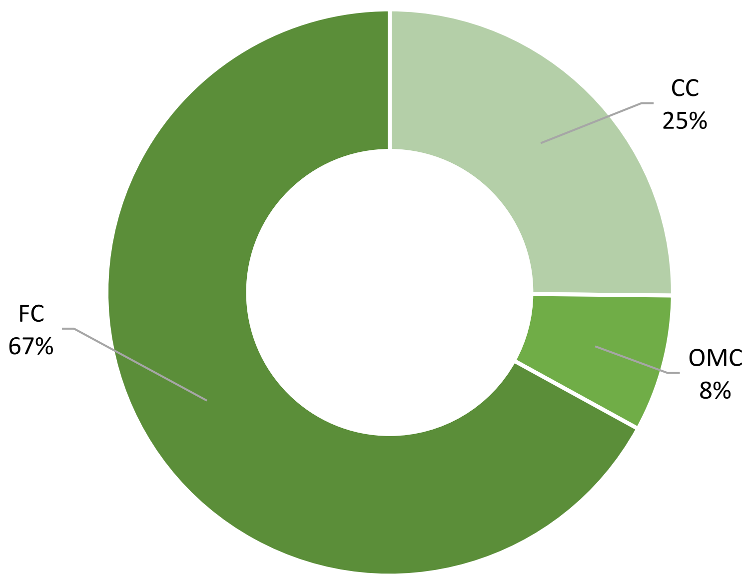


Figure 5.7. Distribution of the levelized total revenue requirement of the liquefaction plant

Table 5.4. Relevant parameters from the simulation for the estimation of costs of the turbomachinery

Component	**Value, $\dot{W}$ (kW)**
HCM1	481
HCM2	505
HeCM1	1,267
HeCM2	2,234
HeCM3	5,551
HeCM4	7,406
HeT1	1,486
HeT2	550
HeT3	220
HeT4	78
HT1	30

Table 5.5. Estimation of costs of the hydrogen liquefaction plant (million US$$_{2021}$)

	BMC	**Contingencies**	**Engineering & Supervision**	**Construction**	**FCI**
HCM1	8.6	1.3	1.3	1.3	12.4
HIC1	1.0	0.1	0.1	0.1	1.4
HCM2	9.3	1.4	1.4	1.4	13.4
HIC2	1.1	0.2	0.2	0.2	1.6
HX1	3.1	0.5	0.5	0.5	4.4
HX2	0.9	0.1	0.1	0.1	1.3
HX3	0.7	0.1	0.1	0.1	1.0
HX4	0.7	0.1	0.1	0.1	1.0
HT	0.4	0.1	0.1	0.1	0.5
HeCM1	4.5	0.7	0.7	0.7	6.5
HeIC1	0.2	0.0	0.0	0.0	0.3
HeCM2	8.6	1.3	1.3	1.3	12.5
HeIC2	0.3	0.0	0.0	0.0	0.4
HeCM3	3.4	0.5	0.5	0.5	4.9
HeIC3	0.5	0.1	0.1	0.1	0.8
HeCM4	4.9	0.7	0.7	0.7	7.0
HeIC4	0.7	0.1	0.1	0.1	0.9
T1	2.5	0.4	0.4	0.4	3.6
REC1	2.2	0.3	0.3	0.3	3.2
T2	1.5	0.2	0.2	0.2	2.1
REC2	2.2	0.3	0.3	0.3	3.2
T3	0.8	0.1	0.1	0.1	1.1
REC3	1.9	0.3	0.3	0.3	2.8
T4	0.7	0.1	0.1	0.1	1.0
TOT	60.4	9.1	9.1	9.1	87.5

Table 5.6. Relevant parameters from the simulation for the estimation of costs of the heat exchangers

Component	Parameters	Value
HX1	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	2,689 200 4.8
HX2	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	903 200 9.5
HX3	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	252 200 4.3
HX4	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	81 100 2.9
REC1	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	4,404 100 7
REC2	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	5,408 100 9
REC3	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	3,295 100 6.7
HIC1	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	831 70 6.5
HIC2	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	869 70 6
HeIC1	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	2,083 300 4.3
HeIC2	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	3,730 300 4.8
HeIC3	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	9,365 300 6
HeIC4	$\dot{Q}$ (kW) U (W/m^2 K) ΔT (K)	10,103 300 6.3

Table 5.7. Economic analysis hydrogen liquefaction plant (values in million US$$_{2021}$)

Carrying Charges		
	FCI	87.5
	Investment 1 (60%)	52.5
	Investment 2 (40%)	35.0
	Interest investment 1	17.3
	Interest investment 2	11.3
	TCI	13.4
	CC_L (million US$/year)	13.7
Operation and maintenance costs		
	OMC	8.2
	OMC_{Lev} (million US$/year)	10
Fuel costs		
	Electricity price (US$ /MWh)	110
	Electricity requirement (MW)	15
	Electricity	12.3
	FC_{Lev} (million US$/year)	16.1
Total Revenue Requirement (million US$/year)		27.5

This thesis explores the large-scale regasification of liquid hydrogen, which involves three interconnected subsystems for regasification and power generation. The first subsystem operates at higher temperatures and utilizes an open gas turbine system. The second subsystem is a closed-cycle gas turbine that uses helium as the working fluid. Finally, the third subsystem is the hydrogen regasification, operating at cryogenic temperatures.

The OGT system utilizes a two-compression aero-derivative gas turbine system, namely the General Electric LMS100. This system is highly efficient and can effectively handle a fuel mixture containing up to 30% hydrogen without requiring significant modifications to the gas turbine. The proposed cogeneration plant, discussed in this research, can benefit from its location in the port by utilizing seawater in the intercooler of the OGT to cool down the compressed air. It should be noted that water filters and a clean process were not considered in the analysis. The electricity generated by the cogeneration plant can be utilized to power the facilities in the port and can operate independently without relying on external electricity sources.

The temperature difference within the cogeneration system is significant, ranging from 1290°C after the combustion process to -253°C for the incoming liquid hydrogen. Due to this substantial temperature difference, an intermediate closed cycle is required between the OGT and the hydrogen regasification process. The working fluid selected for this CGT is helium, as it possesses the ability to exchange heat effectively under cryogenic conditions and facilitate the regasification of liquid hydrogen. Six configuration scenarios were compared (see Table 5.8) with and without a recuperator in the intermediate cycle. The pressure of this intermediate cycle before entering the helium compressor was also evaluated; 2.8 bar in three scenarios and 12 bar in the other three scenarios.

The large-scale regasification of hydrogen poses challenges associated with the cryogenic temperature of the LH_2 and the properties of the hydrogen. Still, it also represents a potential to utilize the exergy transferred when the hydrogen is regasified (20.4 MW) that would otherwise be destroyed. The efficiencies of each scenario for the regasification of LH_2 are presented in Figure 5.8. The distribution of exergy efficiency of each component is presented in Table 5.9.

An important and relevant parameter is the mass flow rate of hydrogen, which considerably decreases when there is a recuperator. Hence, the efficiency of the plant is increased with the addition of the recuperator, but the amount of hydrogen that can be regasified under the same conditions decreases (see Figure 5.9). More calculations related to each scenario are presented in Table 5.10.

The mass flow rates and parameters of each stream are found in Table 4.3. An exergetic efficiency of 62% was calculated for scenario 2, which will be considered further for the economic analysis, and a total exergy destruction of 144 MW was also calculated. The combustion chamber is the component with the highest exergy destruction, followed by the hydrogen regasifier, as shown in Figure 5.10. All the results of the exergy analysis for scenario 2 are presented in Table 5.11.

The physical exergy can be split into thermal and mechanical exergy, and for streams operating under environmental temperature, it is of particular interest to calculate the split of the physical exergy. The split of the mechanical and thermal parts of the physical exergy for the helium in the CGT and the hydrogen in the regasification process is presented in Figure 5.11. Stream 17 (compressed hydrogen gas) and stream 15 (liquid hydrogen) draw particular attention since the physical exergy consists of mainly mechanical and thermal exergy for each stream, respectively. For the compressed gas, the physical exergy is mostly mechanical exergy, while for the liquid hydrogen the thermal exergy plays an important role. Therefore, it can be concluded that hydrogen regasification and compression to delivery conditions is a process in which all the thermal exergy of the hydrogen stream is transformed into mechanical exergy. For the helium cycle, the physical exergy has both components in each stream of the CGT.

Before the liquid hydrogen chain can become a reality, several obstacles need to be overcome. Firstly, the infrastructure for each individual component of the entire hydrogen supply chain must be constructed and interconnected. This infrastructure will resemble the existing infrastructure for fossil fuels and liquid natural gas, and certain elements can be repurposed, such as refurbished pipelines. Additionally, a competitive and well-established market needs to be established. Significant improvements in performance, cost, and technology readiness level are required throughout the entire chain, including production, storage, and utilization of hydrogen.

Liquid hydrogen ships are already a reality, and large-scale pilot projects have been initiated. Therefore, there is a strong demand to prepare and propose technologically feasible hydrogen hub ports that can integrate green hydrogen into each country's national grid. The configuration suggested in this research serves as a useful foundation for the regasification requirements within the EU, but it should be further optimized and adjusted to meet the needs of each country.

One advantage of the proposed configuration presented in this thesis (see Figure 4.4) is the utilization of well-established technology throughout the entire process. The mature technology ensures a long operational lifespan for the cogeneration power plant. Another particularity is that it could use a fuel mixture incorporating regasified hydrogen. This approach reduces the mass flow rate of fuel required and decreases the amount of natural gas needed in the combustion chamber; however, it is more expensive. Therefore, a detailed economic analysis was performed.

Lastly, the integration of a large-scale regasification plant within the port would enable the feasible distribution of green hydrogen gas into the national gas grid or its further distribution via trucks within each country.

Table 5.8. Configurations of hydrogen regasification considered in this thesis

Scenarios	Recuperator	Pressure before Helium CGT
1	No	2.8
2	Yes	2.8
3	No	12.0
4	Yes	12.0
5	Yes	2.8
6	Yes	12.0

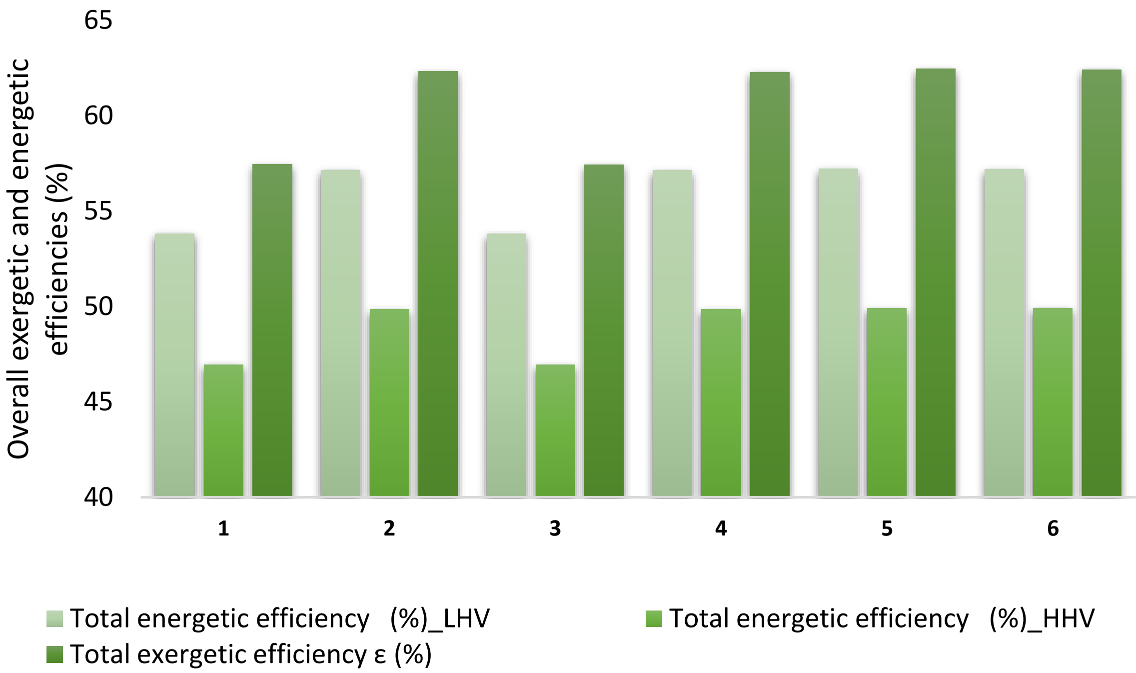


Figure 5.8. Efficiencies of each scenario for the regasification of liquid hydrogen

Table 5.9. Exergetic efficiency of each component in each scenario (values in %)

Component	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
ACM1	94	94	94	94	94	94
ACM2	94	94	94	94	94	94
CC	72	72	72	72	72	72
EXP	97	97	97	97	97	97
HX1	39	91	39	91	91	91
HeT	90	90	90	90	90	90
HX2	0	68	0	68	68	68
HX3	43	81	43	81	83	83
HeCM	92	92	92	92	93	92
HP	89	89	89	89	89	89
Total	55	62	55	62	62	62

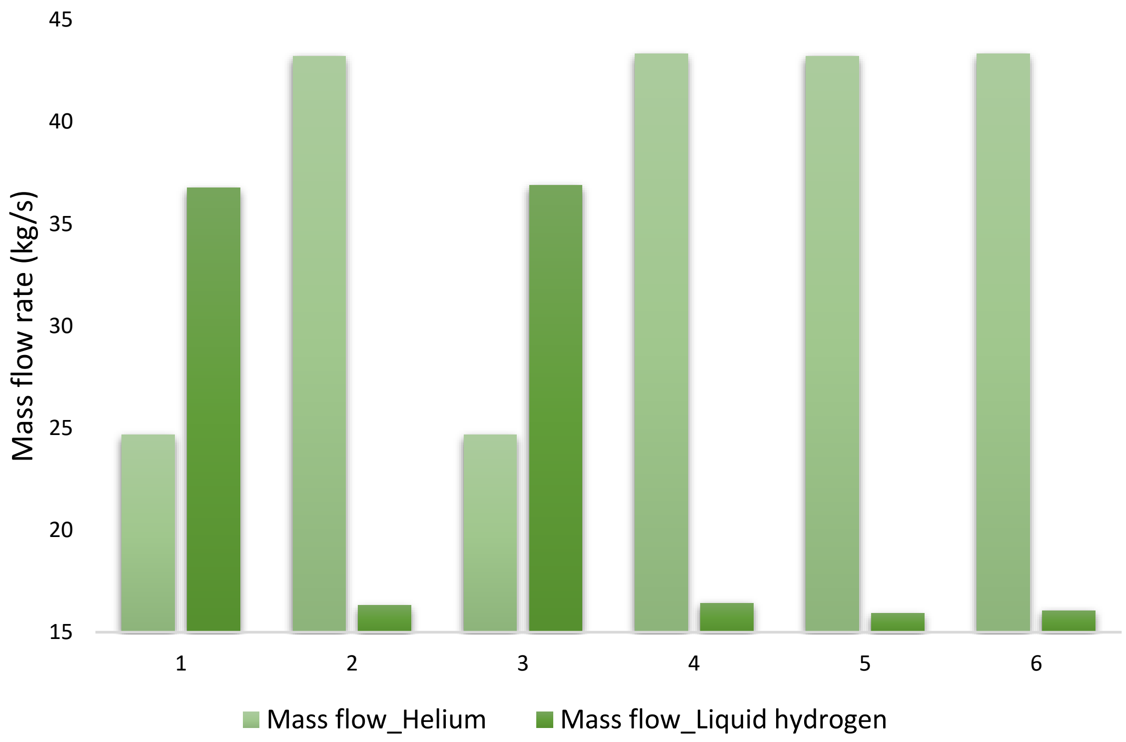


Figure 5.9. Amount of mass flow rate of helium and liquid hydrogen in each scenario

Table 5.10. Relevant parameters for each scenario of the hydrogen regasification plant

		Scenario					
Component	**Parameter**	**1**	**2**	**3**	**4**	**5**	**6**
ACM	η (%)	0.90	0.90	0.90	0.90	0.90	0.90
HeCM	η (%)	0.85	0.85	0.85	0.85	0.85	0.85
HP	η (%)	0.67	0.67	0.67	0.67	0.67	0.67
EXP	η (%)	0.94	0.94	0.94	0.94	0.94	0.94
HeT	η (%)	0.88	0.88	0.88	0.88	0.88	0.88
HT	η (%)	0.85	0.85	0.85	0.85	0.85	0.85
HX1	ΔT_{min} (K)	20	20	20	20	20	20
HX2	ΔT_{min} (K)	20	20	20	20	20	20
HX3	ΔT_{min} (K)	15	15	15	15	15	15
IC	ΔT_{min} (K)	125	125	125	125	125	125
CC	T_{max} (°C)	1290	1290	1290	1290	1290	1290
Mass flow Air	$\dot{m}$ (kg/s)	200.0	200.0	200.0	200.0	200.0	200.0
Mass flow Fuel	$\dot{m}$ (kg/s)	4.3	4.3	4.3	4.3	4.3	4.3
Mass flow He	$\dot{m}$ (kg/s)	24.7	43.2	24.7	43.3	43.2	43.3
Mass flow LH_2	$\dot{m}$ (kg/s)	36.8	16.3	36.9	16.4	15.9	16.1
Ratio He/LH_2		0.671	2.65	0.669	2.6	2.7	2.7
Pressure (before HeCM)	p (bar)	2.8	2.8	12.0	12.0	2.8	12.0
Total energetic efficiency	LHV (MJ/kg)	53.8	57.1	53.8	57.1	57.2	57.2
Total exergetic efficiency	ε (%)	57.4	62.3	57.4	62.2	62.4	62.4

Table 5.11. Exergy analysis regasification of liquid hydrogen for scenario 2 (see Table 5.8)

Component	$\dot{W}$ (kW)	$\dot{Q}$ (kW)	$\dot{E}_{F,k}$(kW)	$\dot{E}_{P,k}$ (kW)	$\dot{E}_{D,k}$ (kW)	ε_k (%)	$y_{D,k}$ (%)	$y^*_{D,k}$(%)
ACM1	46,380		46,380	43,516	2,864	94	0.7	2.0
IC		26,620	Dissipative		10,049			7.0
ACM2	63,520		63,520	59,960	3,560	94	0.8	2.5
CC		347,502	228,047	163,439	64,608	72	14.8	44.8
EXP	218,457		224,930	218,457	6,472	97	1.5	4.5
HX1		72,853	32,911	30,015	2,896	91	0.7	2.0
He-T	68,487		76,165	68,487	7,677	90	1.8	5.3
HX2		54,626	26,129	17,752	8,376	68	1.9	5.8
HX3		18,533	106,799	86,418	20,380	81	4.7	14.1
He-CM	14,276		78,529	72,566	5,963	92	1.4	4.1
H-P	3,292		101,739	90,438	11,300	89	2.6	7.8
Total	159,476		435,947	271,673	144,147	62	33.1	100.0

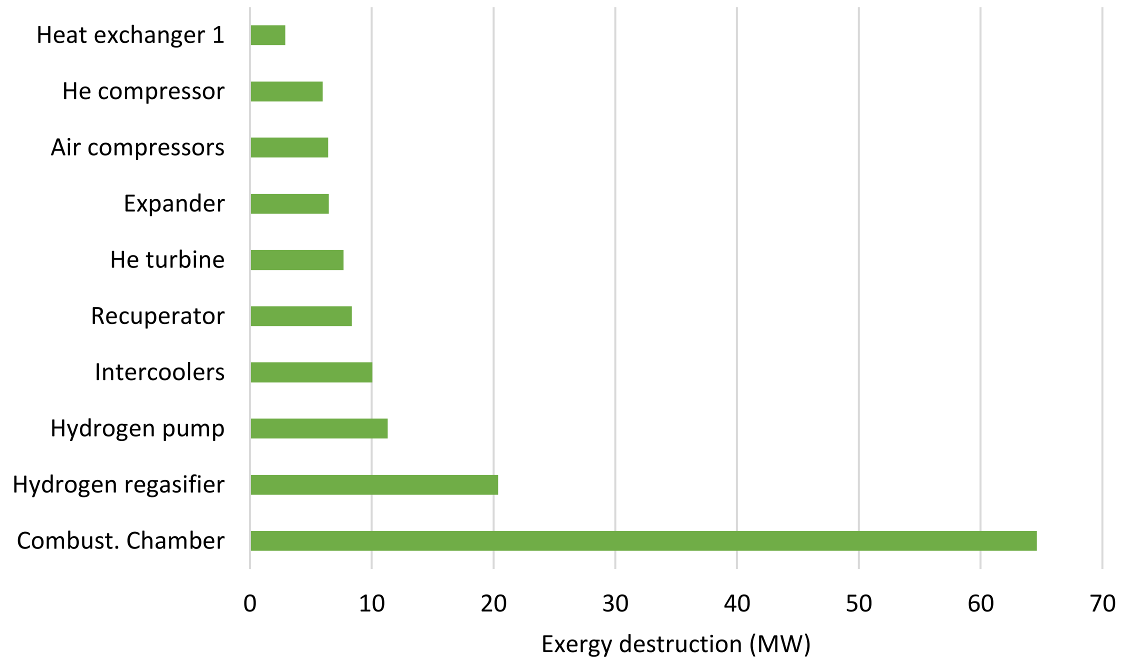


Figure 5.10. Exergy destruction of each component of the regasification of liquid hydrogen

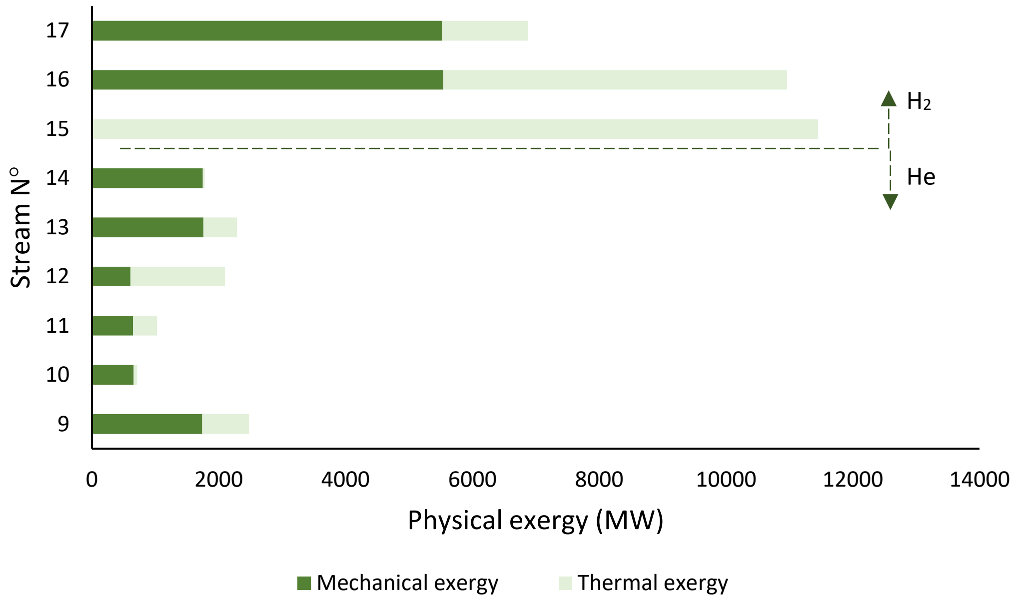


Figure 5.11. Distribution of physical exergy in the regasification of liquid hydrogen

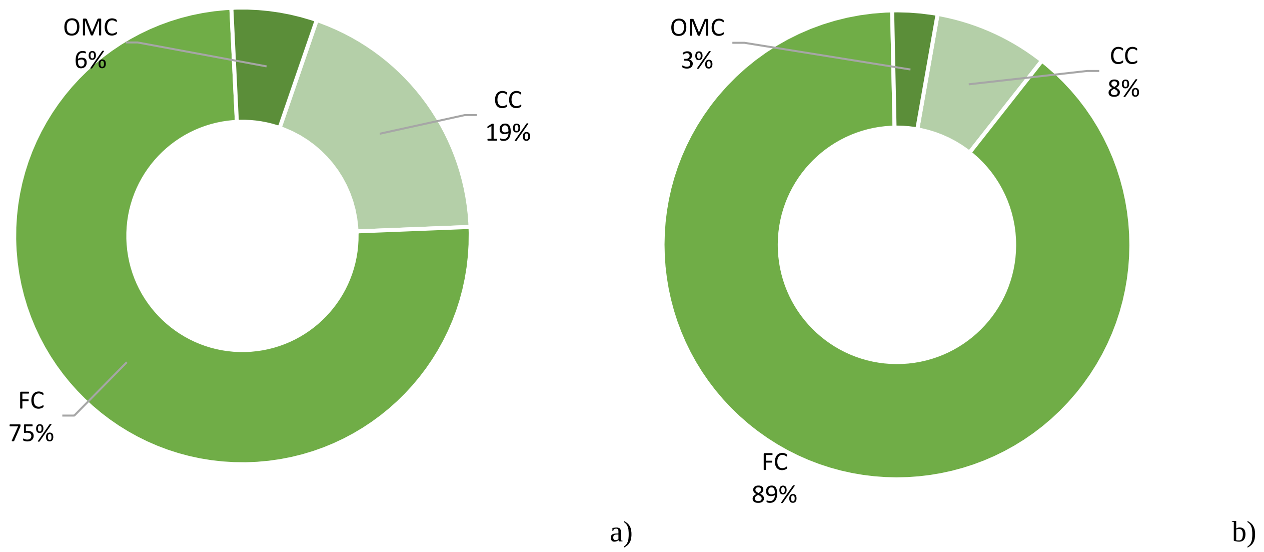


Figure 5.12. Distribution of the total revenue requirement in levelized carrying charges (CC_{Lev}), operation & maintenance costs (OMC_{Lev}), and fuel costs (FC_{Lev}):
a) 100% NG as fuel and b) 70% NG and 30% H_2 as fuel

For the economic analysis, only scenario 2 presented in Table 5.8 was considered. The total revenue requirement method was also applied to the regasification of liquid hydrogen. The fuel cost dominates the total cost for this project; therefore, two scenarios are considered a) using natural gas (NG) as fuel for the OGT and b) using a mixture of NG (70%) and H_2 (30%) as fuel for the OGT. The cost of the regasified hydrogen for both cases is calculated. The levelized TRR for 7446 h/a operating time of the plant corresponds to 227.7 million US$ for the first scenario and almost double the amount for scenario b) 444.1 million US$. The distribution of TRR is shown in Figure 5.12.

The cost of the product for regasified liquid hydrogen for both scenarios was also estimated and presented in Figure 5.13. For scenario a) the levelized cost of regasified hydrogen amounts to 0.74 US$/kg$_{H2}$. Adding the cost of liquid hydrogen (10.45 US$/kg$_{H2}$ [97]), a total cost of the regasified green hydrogen of 11.19 US$/kg$_{H2}$ is calculated, excluding the costs for transportation. While for scenario b) the regasification cost amounts to 1.4 US$/kg$_{H2}$. Relevant parameters necessary for the calculation of the fuel costs and the operation and maintenance costs are summarized in Table 5.12.

Table 5.12. Relevant parameters necessary for the calculation of the fuel costs and the operation and maintenance costs for the regasification of liquid hydrogen

Parameters	Value
Capital recovery factor	0.117
k_{FC}	0.945
k_{OMC}	0.955
CELF (FC)	1.373
CELF (OMC)	1.494

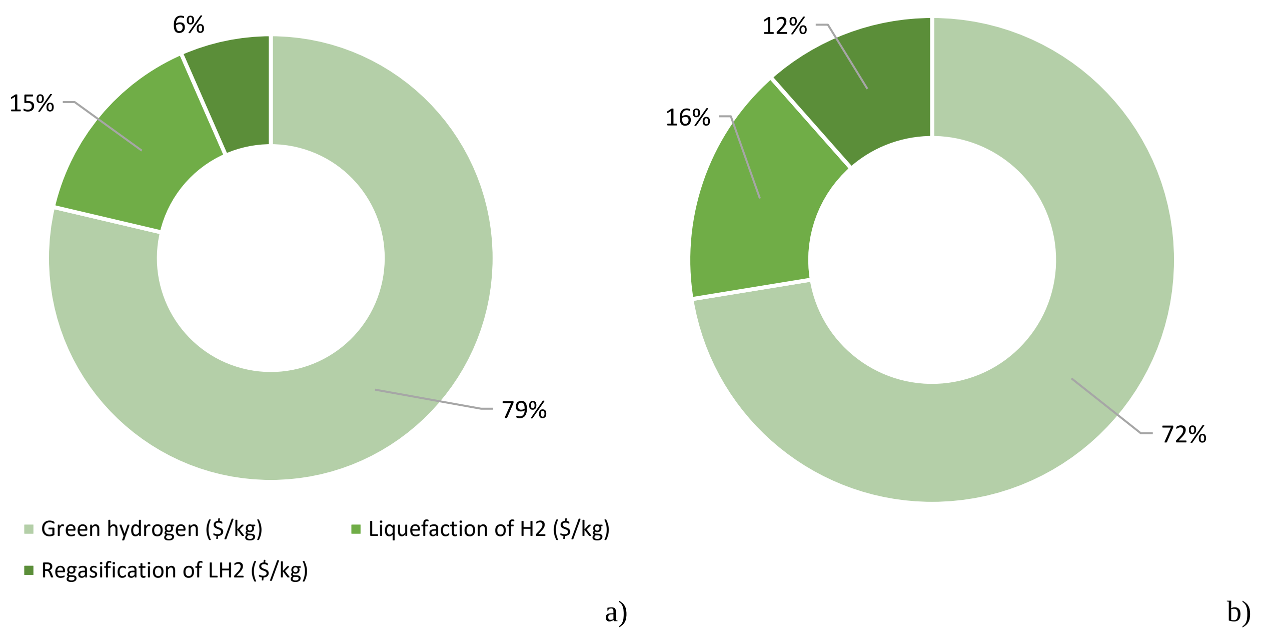


Figure 5.13. Distribution of the cost of the green liquid hydrogen chain: a) 100% NG as fuel and b) 70% NG and 30% H_2 as fuel

The distribution of the PEC of the components of the system is shown in Figure 5.14. The cost is analyzed with various assumptions from cost figures and equations in the literature. The factors for design, material pressure, and temperature are also chosen from the estimations in the literature according to fluid specifications.

The turbomachinery accounts for most of the investment cost. The expander of the OGT system has the highest PEC (23%), and the OGT accounts for 54 % of the total PEC of the system. The CGT, excluding the hydrogen regasifier (HX2) accounts for 33 % of the PEC of the entire plant, while the regasification of the hydrogen (hydrogen pump + hydrogen regasifier) accounts for 13 % of the total PEC. The helium turbomachinery is especially expensive compared to the turbomachinery for other working fluids of a CGT, such as nitrogen, which can be used for the LNG regasification. In addition, the helium compressor is particularly expensive since it deals with cryogenic temperatures (-228°C to -171°C). The total PEC was calculated for the year 2021 and amounted to 66.9 million US$.

A detailed economic analysis was conducted for the regasification of liquid hydrogen. For the detailed calculations, only the scenario where the fuel consists of 100% NG will be presented due to the considerably lower product cost.

The breakout of the total capital investment costs is shown in Table 5.13. The allowance for funds used during construction (AFUDC) is financed half by debt and half by common equity, and the main calculations are shown in Table 5.14 and Table 5.17. The total AFUDC for the first year corresponds to 24.5 million US$ by the end of 2026, just before construction, or 17.5 million US$ in the middle of 2023.

The specific cost of regasified hydrogen varies depending on the operating hours of the plant. For LNG cogeneration plants, full-time is usually considered; however, non the demand or offer of hydrogen could satisfy this operating time. Therefore, a sensitivity analysis of the hydrogen regasification cost according to the operating hours from 2600 h/a to full-time is shown in Figure 5.15. The regasification cost is 1.1 US$/$kg_{H2}$ – 0.7 US$/$kg_{H2,}$ respectively. Adding the cost of LH_2 10.45 US$/$kg_{LH2}$, the total cost of the regasified green hydrogen, excluding the transport and considering the production, liquefaction, and regasification, amounts to 11.56 US$/$kg_{H2}$ – 11.15 US$/$kg_{H2}$, respectively.

The depreciable and non-depreciable capital investments have been calculated for tax purposes and escalated to the beginning of the construction year, 2027, as summarized in Table 5.15.

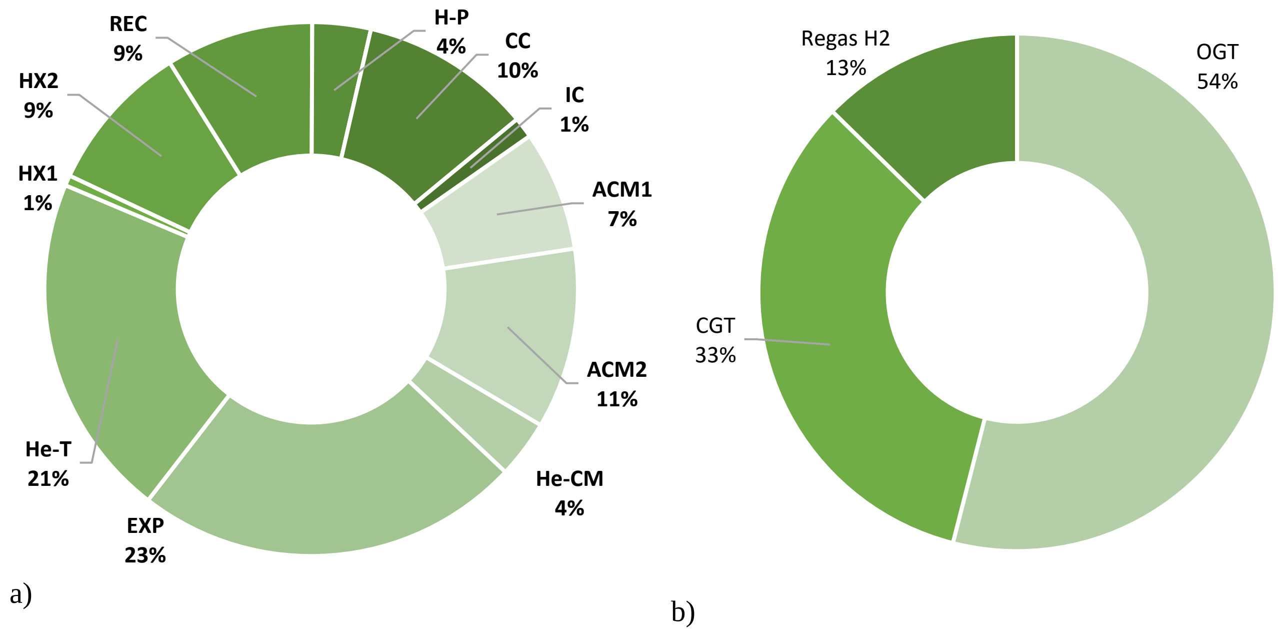


Figure 5.14. Purchased Equipment Cost share of the cogeneration plant: a) distribution by component and b) distribution by sub-system

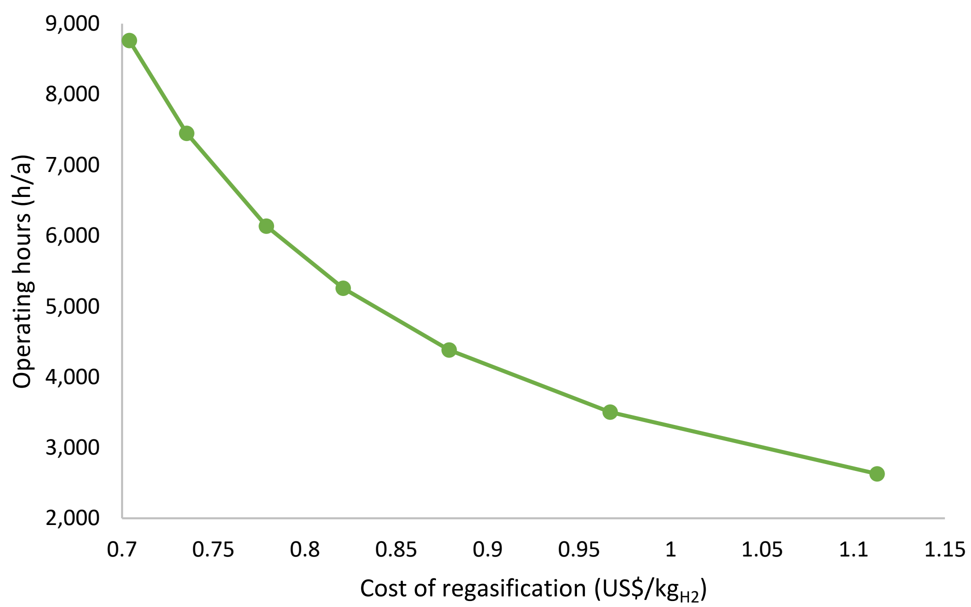


Figure 5.15. Sensitivity analysis of the hydrogen regasification cost per operating annual hours

Table 5.13. Total capital investment of the regasification of hydrogen cogeneration plant values in (values in million $US\$_{2021}$)

I. Fixed Capital Investment	
A. Direct costs (DC)	
A.1 Onsite costs	
Total PEC2021	**66.9**
Equipment Installation	22.1
Piping	23.4
Instrumentation and controls	8.0
Electrical equipment and materials	8.7
Total Onsite costs	**129.1**
A.2 Offsite costs	-
Land	3.0
Architectural work	14.0
Service facilities	23.4
Total offsite costs	**40.4**
Total DC	**169.6**
B. Indirect costs (IC)	-
Engineering and supervision	13.6
Construction costs	25.4
Contingencies	25.0
Total IC	**64.0**
Fixed Capital Investment	**233.6**
II. Other Outlays	-
Startup costs	18.9
Working capital	30.3
Allowance for funds during construction (AFUDC)	17.6
Total other outlays	**66.5**
Total Capital Investment	**300.1**

Table 5.14. Allowance for funds used during construction of two years (values in million US$$_{2021}$)

Year		Plant-Facilities Investment			Common Equity (50%)		Debt (50%)	
Design and construction	**Calendar**	**In mid-2023**	**Amount of escalation**	**Escalated investment**	**Escalated investment**	**AFUDC**	**Escalated investment**	**AFUDC**
1	2025	92.2	9.4	101.7	50.8	7.8	50.8	7.8
2	2026	138.3	21.8	160.2	80.1	3.9	80.1	3.9
	Subtotal	230.6	31.3	261.8	130.9	11.7	130.9	11.7
1		**Cost of land**						
	2025	3.0	0.3	3.3	1.6	0.08	1.6	0.06
		Start-up costs						
2	2026	18.7	2.9	21.6	10.8	527.91	10.8	0.4
	Total					12.3		12.2

Table 5.15. Depreciable and non-depreciable capital investment (values in million US$$_{2021}$)

Cost of land	3.0
Escalated plant facilities investment	261.8
Escalated Startup costs	21.6
Escalated working capital	35.9
Total net outlay	322.4
Common equity AFUDC	12.3
Debt AFUDC	12.2
Total Capital Investment	346.9
Non-depreciable capital investment	-
Cost of land	3.0
Working capital	35.9
Common equity AFUDC	12.3
Total non-depreciable capital investment	51.2
Total depreciable capital investment (TDI)	295.7
Total net capital investment	346.9

The depreciation method modified accelerated cost recovery system has been assumed for this example. For internal purposes, straight line depreciation has been assumed. The deferred income taxes and total capital recovery have been calculated for the entire lifetime of the project as presented in Table 5.16.

Finally, the total revenue requirement is calculated for the entire lifetime of the project. It considers all the expenses of the purchase of the equipment, land, startup costs, working capital, the return on common equity of 10%, of interest debt of 8%, all taxes are taken into account, as well as the fuel costs and operation and maintenance costs. The TRR is presented in detail in Table 5.18.

Table 5.16. Depreciation modified accelerated cost recovery system (MACRS) (values in million US$$_{2021}$)

Year of commercial operation	Calendar year	MACRS depreciation factor	Annual tax depreciation	End-year tax book value
0	2026	0	-	296.4
1	2027	5	14.8	281.6
2	2028	9.5	28.2	253.4
3	2029	8.5	25.3	228.1
4	2030	7.7	22.8	205.3
5	2031	6.9	20.5	184.7
6	2032	6.2	18.5	166.3
7	2033	5.9	17.5	148.8
8	2034	5.9	17.5	131.3
9	2035	5.9	17.5	113.8
10	2036	5.9	17.5	96.3
11	2037	5.9	17.5	78.8
12	2038	5.9	17.5	61.3
13	2039	5.9	17.5	43.8
14	2040	5.9	17.5	26.3
15	2041	5.9	17.5	8.7
16	2042	2.9	8.7	-
Total		100		

Table 5.17. Total Capital Recovery of the regasification cogeneration plant (values in million US$$_{2021}$)

						Debt (50%)			Common equity (50%)		
Year of commercial operation	**Calendar year**	**Annual Book depreciation**	**Deferred income taxes**	**Recovery of common equity AFUDC**	**Total Capital Recovery**	**Balance Beginning of Year**	**Book depreciation**	**Adjustment**	**Balance Beginning of Year**	**Book depreciation**	**Adjustment**
1	2027	14.8	-	0.6	15.4	173.5	8.7	-	173.5	6.1	0.6
2	2028	14.8	13.3	0.6	28.7	164.8	8.7	6.7	166.7	6.1	7.3
3	2029	14.8	10.5	0.6	25.9	149.5	8.7	5.2	153.4	6.1	5.9
4	2030	14.8	8.0	0.6	23.4	135.5	8.7	4.0	141.4	6.1	4.6
5	2031	14.8	5.7	0.6	21.1	122.9	8.7	2.9	130.7	6.1	3.5
6	2032	14.8	3.6	0.6	19.0	111.4	8.7	1.8	121.1	6.1	2.4
7	2033	14.8	2.7	0.6	18.1	100.9	8.7	1.3	112.5	6.1	1.9
8	2034	14.8	2.7	0.6	18.1	90.9	8.7	1.3	104.5	6.1	1.9
9	2035	14.8	2.7	0.6	18.1	80.9	8.7	1.3	96.4	6.1	2.0
10	2036	14.8	2.7	0.6	18.1	70.8	8.7	1.3	88.3	6.1	1.9
11	2037	14.8	2.7	0.6	18.1	60.8	8.7	1.3	80.3	6.1	2.0
12	2038	14.8	2.7	0.6	18.1	50.8	8.7	1.3	72.2	6.1	1.9
13	2039	14.8	2.7	0.6	18.1	40.8	8.7	1.3	64.2	6.1	2.0
14	2040	14.8	2.7	0.6	18.1	30.8	8.7	1.3	56.1	6.1	1.9
15	2041	14.8	2.7	0.6	18.1	20.8	8.7	1.3	48.0	6.1	2.0
16	2042	14.8	-6.1	0.6	9.3	10.8	8.7	-3.0	39.9	6.1	-2.4
17	2043	14.8	-14.8	0.6	0.6	5.1	8.7	-7.4	36.3	6.1	-6.8
18	2044	14.8	-14.8	0.6	0.6	3.8	8.7	-7.4	36.9	6.1	-6.8
19	2045	14.8	-14.8	0.6	0.6	2.6	8.7	-7.4	37.6	6.1	-6.8
20	2046	14.8	-14.8	0.6	0.6	1.3	8.7	-7.4	38.2	6.1	-6.8

Table 5.18. Total revenue requirement of the hydrogen regasification cogeneration plant (values in million $US\$_{2021}$)

Year	Calendar year	Capital recovery	Return on common equity	Interest on debt	Income taxes	Other taxes and insurance	Fuel costs (NG)	OMC	TRR (current dollars)	TRR (constant dollars)	Annuity TRR (current dollars)
1	2027	15.4	17.3	17.3	5.4	5.2	124.1	10.5	195.3	160.7	177.6
2	2028	28.7	16.7	16.5	5.2	5.2	129.1	11.0	212.4	166.4	175.5
3	2029	25.9	15.3	14.9	4.8	5.2	134.3	11.5	212.0	158.2	159.3
4	2030	23.4	14.1	13.6	4.4	5.2	139.6	12.1	212.5	151.0	145.1
5	2031	21.1	13.1	12.3	4.1	5.2	145.2	12.7	213.7	144.7	132.7
6	2032	19.0	12.1	11.1	3.8	5.2	151.0	13.4	215.7	139.1	121.8
7	2033	18.1	11.3	10.1	3.6	5.2	157.1	14.0	219.3	134.6	112.5
8	2034	18.1	10.4	9.1	3.3	5.2	163.3	14.7	224.2	131.1	104.6
9	2035	18.1	9.6	8.1	3.1	5.2	169.9	15.5	229.5	127.8	97.3
10	2036	18.1	8.8	7.1	2.8	5.2	176.7	16.2	235.0	124.6	90.6
11	2037	18.1	8.0	6.1	2.6	5.2	183.7	17.1	240.8	121.6	84.4
12	2038	18.1	7.2	5.1	2.4	5.2	191.1	17.9	247.0	118.8	78.7
13	2039	18.1	6.4	4.1	2.1	5.2	198.7	18.8	253.5	116.1	73.4
14	2040	18.1	5.6	3.1	1.9	5.2	206.7	19.7	260.3	113.6	68.5
15	2041	18.1	4.8	2.1	1.6	5.2	215.0	20.7	267.5	111.2	64.0
16	2042	9.3	4.0	1.1	1.4	5.2	223.6	21.8	266.4	105.4	58.0
17	2043	0.6	3.6	0.5	1.3	5.2	232.5	22.9	266.6	100.5	52.7
18	2044	0.6	3.7	0.4	1.3	5.2	241.8	24.0	277.0	99.4	49.8
19	2045	0.6	3.8	0.3	1.3	5.2	251.5	25.2	287.9	98.4	47.1
20	2046	0.6	3.8	0.1	1.3	5.2	261.5	26.5	299.1	97.4	44.5
										SUM	1,938.3
										TRR_L	227.7

The profitability of this cogeneration plant under the conditions mentioned above, 100% NG as fuel for the OGT, and all the other assumptions summarized in Table 5.19 are evaluated with two statics methods, the average rate of return (ARR) and payback (PB) period. Also, two dynamic methods that consider the time value of money are considered, the net present value (NPV) and the internal rate of return (IRR). These calculations alone do not show a realistic scenario to decide whether the project should be realized. The four methods provide complementary information for the decision. The ARR of the plant amounts to 1.84%, a very low value, which would probably not attract investors to take part in this project. The payback period of the project, applying Method 1, exceeds the lifetime for taxes purposes (15 years). The net present value is a negative value for the minimum rate of return considered in this research of 10%; therefore, the project cannot meet this minimum rate of return. The actual rate of return of the project corresponds to only 1.3%, which is not an attractive IRR for an investor.

Considering future governmental financial assistance to the entire hydrogen economy-related industries seems necessary to make unprofitable projects, such as this one, profitable. The European Union aims to boost the hydrogen economy this year and include tax credits [248] to counteract the US green subsidies of up to 3 US$/$kg_{H2}$ to make the green hydrogen produced in the EU competitive [249]. Similar support packages are expected for other components of the hydrogen chain.

Table 5.19. Profitability of the hydrogen regasification plant

Profitability	**Value**
Average Rate of Return (%)	1.8
Payback period (Method 1, years)	17.6
Payback period (Method 2, years)	14.2
Net present value (million US$$_{2021}$)	-261.9
Internal rate of return (%)	1.3

5.2. Comparison of hydrogen "colors"

The main criteria for evaluating the hydrogen production pathways were carefully selected and are summarized and shown in Figure 5.16, the colors of the lines represent the hydrogen color with the highest value for each category.

Today, almost all the hydrogen still comes from fossil fuels (83%). Mostly from gray hydrogen (62%), followed by 19% from a combination of brown and black hydrogen and 0.7% from blue hydrogen. Only 0.04% came from green hydrogen. The rest was produced as a byproduct in the chemical industry [18].

The most stable and the least expensive hydrogen production pathways are the ones related to the conventional methods to produce it: gray, black, and brown hydrogen. Their cost depends on the fossil fuel source they use, and it is expected to increase soon and be affected by CO_2 taxes or the energy crisis. Currently, gray hydrogen is the least expensive, and its cost ranges from 0.7-2.3 US$/kg$_{H2}$ [250], [18], [6], followed by black and brown hydrogen 1.3-2.5 US$/kg$_{H2}$ [250] [18].

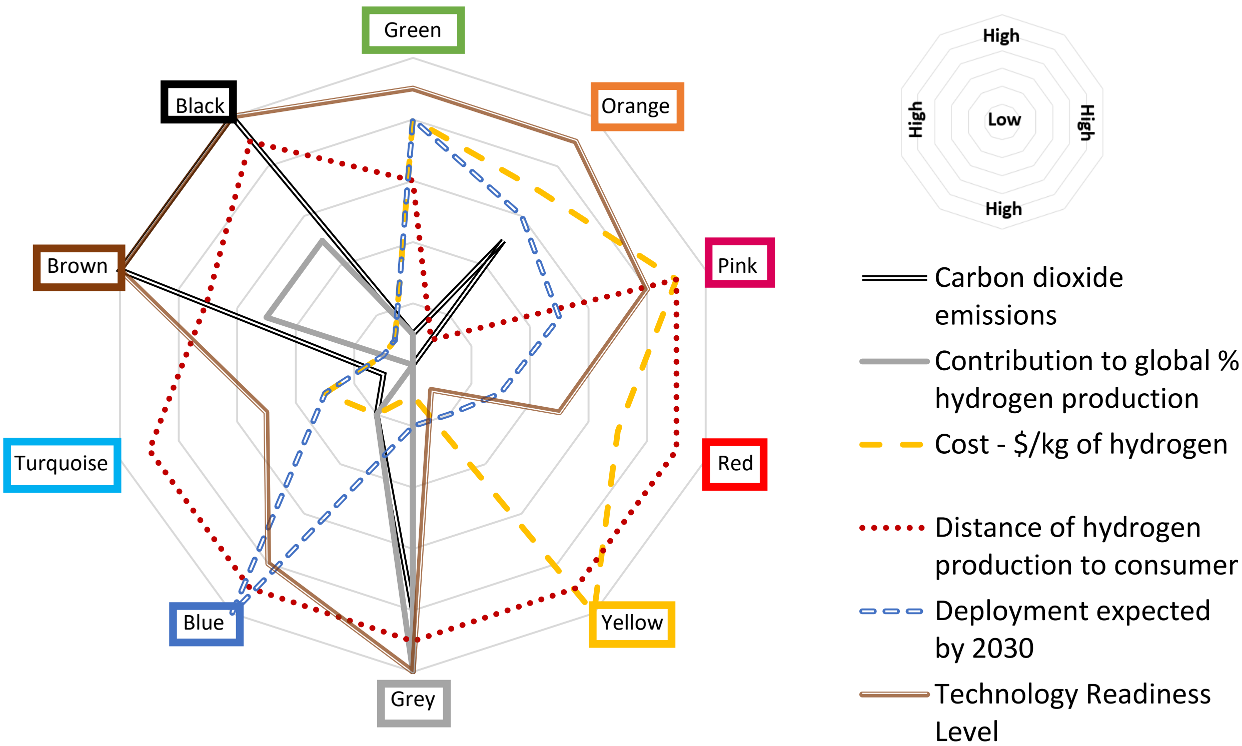


Figure 5.16. Comparison of hydrogen "colors" *[44]*

As CO_2 taxes increase, their cost will increase and help make blue, turquoise, and green hydrogen more competitive. The cost of blue hydrogen ranges from 1.4-3.2 US$/kg$_{H2}$ [250] [251] [18], since the addition of CCUS increases the cost of production [252]. The cost of turquoise hydrogen is reported to be slightly higher than that of blue hydrogen, 1.6-3.4 US$/kg$_{H2}$ [250], since the technology readiness level is lower than that of blue hydrogen.

The cost of green hydrogen varies the most among all the colors, from 1.9-8.2 US$/kg$_{H2}$ [18] [6] [250]. This is mainly due to the different RES technologies used to power the electrolyzers. Countries such as Chile and some North African countries can produce green hydrogen using solar PV at the lower ends of the range, while northern European countries will be at the high end of the range [47]. In the case of green wind energy, the cost depends on whether it is onshore or offshore and whether it is centralized or decentralized production. The cost of electricity depends on the capital cost of RES as the demand for green hydrogen increases, and policies provide incentives for the construction of more green hydrogen plants; green hydrogen is expected to become cost-competitive by 2030 [31]. The low technology readiness level of yellow hydrogen affects its high cost from 7.9-8.4 US$/kg$_{H2}$ [250]. Also, the cost is associated with solar reactors and thermal and chemical storage.

Pink hydrogen could be an economically viable, stable, and cost-effective technology, 3.8-7 US$/kg$_{H2}$ [18] [250]. The cost depends mainly on the capital cost of the nuclear power plant. However, nuclear power plants are expensive, and it takes a long time to build a new plant. In some countries where nuclear energy is already available, such as France, Canada, the United States, and China, pink hydrogen could be less expensive than green hydrogen. Red hydrogen would also be cost-competitive in these countries, with reported values from 2.2-2.6 US$/kg$_{H2}$ [250].

Finally, orange hydrogen depends strongly on the energy mix of the country and the price of the electricity used to power the electrolyzers. Therefore, each scenario can be different, and it is recommended to include the cost of the electricity along with the cost of hydrogen production, e.g., 3.35-3.6 US$/kg$_{H2}$ at 6.7 cent US$/kWh (the average industrial rate in the U.S.) [35].

This category depends on the country and its availability of renewable and fossil fuel resources. It also depends on the complexity, size, and safety of the hydrogen production process related to each color. On the one hand, the hydrogen production site involving electrolyzers can be anywhere, even in the place where the hydrogen is needed, for green and orange hydrogen (however, it is expected that many main hydrogen consumer countries will produce part of their green hydrogen and another part will be transported over long distances). On the other hand, if nuclear power is involved in the process, the distance is likely to be significant from the producer to the consumer due to safety issues (pink and red hydrogen). Yellow hydrogen requires a big area for the solar farm; therefore, most likely, it will be far away from the consumers. The conventional methods, such as gray, brown, and black are probably far away, even in another country, due to the availability of resources. The same is true with turquoise and blue hydrogen. The situation changes if the country has coal.

Green and orange hydrogen rely mostly on Alkaline and Polymer Electrolyte Membrane electrolyzers. Both electrolyzers are commercially available with a technology readiness level of 9 [253]. The AWE is cheaper and has been on the market longer than PEM, but in recent years PEM scalation has received significant incentives that have led to a reduction in the price of the electrolyzers. The solid oxide electrolyzer cell (SOEC) electrolyzer is the least developed of the three electrolyzers. The high-temperature steam electrolysis can receive both heat and electricity from

RES or just electricity from RES and heat from waste heat from industry, nuclear energy, solar thermal, or geothermal energy. Both red and yellow hydrogen, while not new technologies are in the early stages of development with a reported TRL of 3 [253]. Water thermolysis is another method of splitting water molecules by decomposing the molecules at high temperatures reaching above 2000 °C. An improvement of these methods is thermochemical water splitting, in which reagents and catalysts are introduced to considerably reduce the temperature and operating time [254]. Both processes are in the early stages of development and can be powered by solar thermal or nuclear energy.

The three conventional fossil fuel-based hydrogen production methods, gray, brow, and black hydrogen, have a TRL of 9, and the introduction of CCUS decreases the TRL for blue hydrogen to 8 [253]. Finally, for turquoise hydrogen, a lower TRL of 6 is reported [253]. The carbon intensity of the pathways compared in this thesis is presented in Figure 5.17.

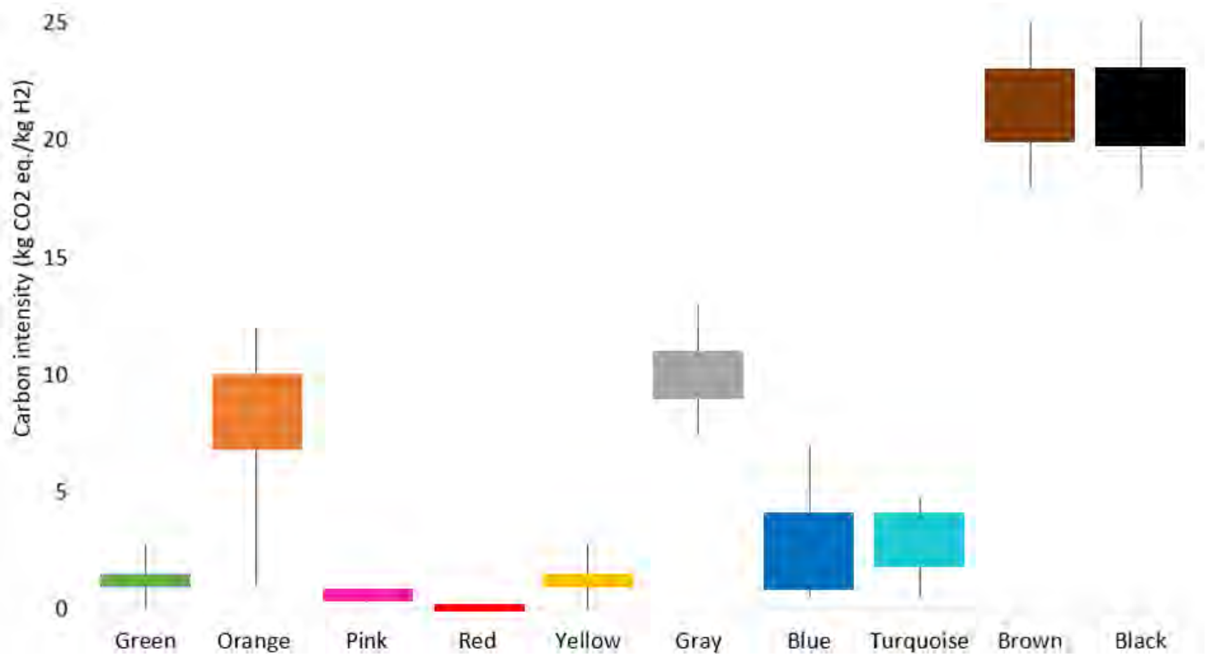


Figure 5.17. Carbon intensity of hydrogen "colors" *[44]*

Many sources agree that the environmental impact of the produced hydrogen should be the most important classification for the routes to produce hydrogen since the driving force for the current hydrogen boom is the need to decarbonize the global economy [255], [47]. Also, the environmental impact of the hydrogen transportation method should be considered in future analyses; for instance, if it is liquid hydrogen, more energy is required for its cryogenic storage [256]. A comparison of the carbon intensity of the associated emissions of ammonia production, methanol, and hydrogen has been reported in [64]. There are many methodologies to assess the impact of each hydrogen color from an environmental point of view. Additionally, the delimitation of the analyzed system might vary from study to study. Some papers only evaluate the production pathway, whereas others consider in a broader scope the entire performance cradle-to-grave and the lifetime of the process. Each study has different assumptions that affect the results. However, they offer a basis to compare the environmental impact of each pathway.

The CO_2 emissions of each production pathway are affected mostly by the sources of hydrogen and energy. For the pathways where water is the feedstock (green, orange, red, pink, and yellow), there are practically no associated CO_2 emissions. For those where fossil fuels are the feedstock, such as gray, black, and brown hydrogen, high CO_2 emissions are inevitable unless CCUS is included. Biomass pathways are characterized as zero (or negative) carbon pathways since biomass is considered a renewable source. There are associated CO_2 emissions; however, the direct emissions from the production process are considered reabsorbed in the formation of biomass [257].

In terms of direct emissions from hydrogen production, green hydrogen is considered a zero-carbon pathway. However, if the life cycle emissions of RES are taken into account, hydro, wind, and solar PV have an associated environmental impact [258]. Furthermore, to have an accurate account of the environmental impact of green hydrogen, it is necessary to consider the emissions of the supply chain. The CO_2 equivalent emissions vary from 0.7-2.8 $kg_{CO2eq.}/kg_{H2}$ if the whole supply chain is considered [250]; other reports do not consider the entire supply chain and report it as low as 0 $kg_{CO2eq.}/kg_{H2}$ [30]. Green hydrogen consumes more water than gray hydrogen. Countries, such as those in the Middle East and North Africa (MENA) region, with a low supply of fresh water, will have to resort to desalination technologies to acquire the required quality of water. Brine disposal must also be considered in the environmental impact analysis [259].

The environmental impact of orange hydrogen depends mainly on the energy mix in the grid. In some countries with very clean energy mix, such as Costa Rica, Iceland, or Paraguay, emissions from orange hydrogen might be very low. In contrast, for China, orange hydrogen emissions would be comparable to that of fossil fuels. For the German grid in 2020, for example, the CO_2 emissions from orange hydrogen would be 370 gCO_2/kWh [30].

Pink and red hydrogen have no direct carbon emissions, but they have other critical environmental impacts from radiation, waste management, and accident risks. Very low associated CO_2 emissions have been reported for pink and red hydrogen, such as 0.3-0.6 $kg_{CO2eq.}/kg_{H2}$ and 0.1 $kg_{CO2eq.}/kg_{H2}$, respectively [250]. When comparing red and yellow hydrogen, red hydrogen provides a more efficient cycle, and the cost of hydrogen is much lower than yellow. This can be attributed to the advancement of nuclear technology. The environmental impact of yellow hydrogen is associated with the supply chain for the construction of the solar farm, in addition to the water required for the process. The types of cycles used will have different environmental impacts. It has been reported in the literature that the Cu-Cl cycle has an environmental impact of less than 1.7 $kg_{CO2eq.}/kg_{H2}$ [260].

The direct carbon emissions from gray hydrogen vary from 7.5-13 $kg_{CO2eq.}/kg_{H2}$ [18]. The carbon intensity of gray hydrogen will increase if upstream methane emissions are taken into account, and this depends on the percentage of fugitive methane assumed in the study. The inclusion of these effects also affects the carbon intensity of blue and might affect the orange hydrogen if fossil fuels are part of the energy mix.

Biomass can be used as feedstock to produce hydrogen via biomass gasification by pyrolysis, steam gasification, or volatile steam reforming. Many challenges arise from its conversion, such as low-carbon conversion rate, acidification potential, and tar formation, which blocks pipelines and affects energy efficiency [261]. Negative CO_2 emissions refer to biomass coupled with CCUS [262]. However, the ecosystem impact of land use and water consumption needs to be addressed and added to studies for more conclusive results.

Blue hydrogen can have different carbon intensity values depending on the technology and the percentage of CCUS applied. For 95% CCUS, carbon intensity varies from 0.8-4.8 $kg_{CO2\ eq.}/kg_{H2}$ [18]. It is important to mention that there are no well-established commercial large-scale CCUS systems yet. There are a few units available to decarbonize hydrogen production in refining in Canada, France and the U.S. [11]. In many projects, the captured carbon is not to be stored but used in oil refining processes or for urea production and eventually released back into the atmosphere [11]. This leads to the question of whether blue hydrogen helps mitigate CO_2 emissions. Furthermore, the long-term effects of indefinite CO_2 storage have also not been extensively studied. A perfect case scenario is almost always assumed.

The quantity of water needed for the water production pathways, its availability, and the level of purity required is a challenge when access to fresh water is limited, or water is not available near the hydrogen production site [263]. Most nations where blue hydrogen is expected to be deployed rely on seawater desalination. The cost of a kg of desalinated water is very low, 0.001 US$, but this water has an associated carbon footprint 44 times higher than normal freshwater [264]. For the green hydrogen, around 9 kg of water is needed to produce 1 kg of hydrogen (theoretically from stoichiometry. This also applies to orange, green, and pink). While gray hydrogen, using SMR, needs only 7 kg of water. However, a more realistic assessment of water consumption can be conducted with a gate-to-grave study. The value of water required for SMR is 11.7 kg_{H2O}/kg_{H2}, while for green hydrogen, around 30 kg_{H2O}/kg_{H2} [265].

Methane pyrolysis in turquoise hydrogen is currently intensively discussed, and it is receiving a lot of investment. This is due to the solid carbon byproduct that eliminates CCUS. An impact of 1.9-4.8 $kg_{CO2\ eq.}/kg_{H2}$ has been reported [250] for this technology.

The estimated carbon dioxide emissions for black and brown hydrogen are between 18-25 $kg_{CO2\ eq.}/kg_{H2}$, and both colors have the highest CO_2 emissions of all colors [250].

5.3. Comparison of hydrogen carriers

This thesis compares four PtX technologies, namely Power-to-Liquid hydrogen, Power-to-Methanol, Power-to-Ammonia, and Power-to-Hydrogen gas, based on their energy vectors. All of these technologies are currently produced on an industrial scale and have a global infrastructure available, although with varying technology readiness level. Criteria such as production process efficiency, energy requirements for producing each substance, storage temperature and pressure, density, gravimetric energy density, the energy required to extract hydrogen and safety considerations such as explosion limits in the air were identified and used to determine the best technology for a study case in Germany.

A graphical comparison of the amount of hydrogen that can be stored in a single cubic meter using the four technologies is given in Figure 5.18. Hydrogen, either in gas (14 kg_{H2}/m^3) or liquid form (71 kg_{H2}/m^3) [266], can store less hydrogen in the same volume as ammonia or methanol. Consequently, the need to consider other more efficient transport and storage alternatives for this element. Methanol has an energy density comparable to ammonia, but it has a lower gravimetric density (12.5 wt%) and volumetric hydrogen contents (99 kg_{H2}/m^3) [184] than ammonia (17.8 wt% and 108 kg_{H2}/m^3) [267]; therefore, ammonia can store more hydrogen than methanol in the same volume. However, the storage conditions of methanol at environmental temperature and pressure are the best of all the studied cases. It should be highlighted that the bond dissociation energies of C-H is 410 kJ/kmol and for N-H is 391 kJ/kmol [268], and the energy required for catalytic cracking of ammonia and dehydrogenation of methanol is also different.

A summary of the advantages and disadvantages of these technologies, based on various categories evaluated in this study, is provided in Figure 5.19. In order to transport hydrogen on a large-scale via gas, well-established pipelines are required. However, in the interest of a swift transition period, it is necessary to find a short-term alternative. When compared, a truck containing ammonia is capable of transporting 7.7 times more hydrogen than a truck with compressed gas alone and 1.5 times more than a truck with liquid hydrogen.

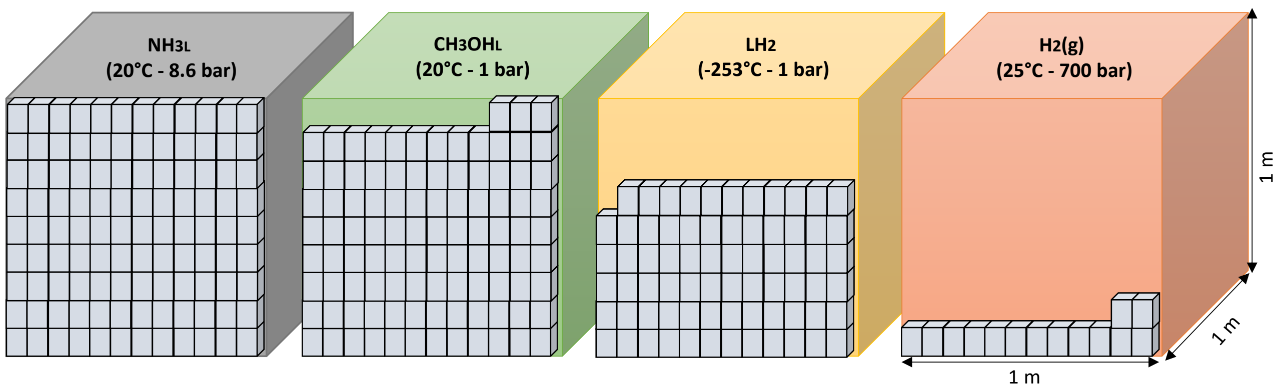


Figure 5.18. Comparison of density of the four substances analyzed in this thesis. Each cube represents 1 kg_{H2}

The costs associated with producing green ammonia have been determined for various North African countries with abundant renewable energy resources. By 2030, it is projected that the cost of importing green hydrogen-derived ammonia from North Africa into Europe will be approximately 500 US$/$t_{NH3}$ [269]. The transportation costs by ship may vary with the distance; for distances between 3,000 km to 6,000 km, a price of 0.7 to 1.12 US$/GJ can be assumed [270]. For instance, the transportation costs from Morocco to Germany were determined to be 1.84 US$/GJ [270]. If ammonia needs to be converted via cracking of ammonia back to hydrogen and nitrogen, an extra cost of around 1 US$/$kg_{NH3}$ must be considered [270]. Ammonia presents some safety issues, which could limit its acceptance and adaptation in some scenarios due to its toxicity. However, ammonia is very versatile and worth to be considered since it can also be directly used as a fuel in fuel cells or gas turbine technology [271].

The levelized cost of delivery of LH_2 by ship over a distance of 8,000 km of 2.7 US$/$kg_{H2}$ was reported as the highest of all the alternatives. For methanol, the value corresponds to 2.4 US$/$kg_{H2}$, while for ammonia, the value is 2.1 US$/$kg_{H2}$ [18].

The energy-intensive nature of maintaining LH_2 in a liquid state during storage and transportation makes liquid hydrogen the most expensive option compared to other solutions considered in this study. This aspect has an impact on the levelized cost. Long-distance deliveries are carried out through highly insulated cryogenic tanks that can typically hold 2,000 kg_{LH2}. However, challenges related to boil-off and transfer losses persist [272].

The green methanol economy is expected to play a significant role in the future as an alternative liquid fuel, and it is well-suited for use as an energy carrier. However, the additional cost of incorporating CCS into this process must be taken into account [273].

In general, efforts are still needed to enhance the efficiency of electrolysis processes. In order to compete with natural gas prices, the cost of producing green hydrogen must decrease to around 1.5-2 US$/$kg_{H2}$ in the next ten years to compete with natural gas prices [14], [15]. According to [274], by 2030, the cost of green hydrogen could potentially reach 1.8 US$/kg, with support from the European Commission's recent 2 US$ billion Clean Hydrogen Partnership.

It is important to emphasize the need for sufficient water supply in regions where the PtX system is to be developed. This issue was raised by researchers several years ago [131] due to the high amount of high-quality water required to produce hydrogen through electrolysis [275]. As mentioned in the previous subsection, from a stoichiometric standpoint, the minimum water requirement for producing 1 kg_{H2} through electrolysis is 9 kg_{H2O}. However, due to inefficiencies and the need for water demineralization, the actual water requirement is much higher [95]. Many suitable locations for green hydrogen production due to abundant renewable resources such as wind and solar energy are also found in the driest regions close to deserts worldwide, such as the MENA region, South Africa, Australia, and the southwest of the U.S. It is crucial for the PtX industry not to compete with local drinking water supplies in these regions, and the costs of water desalination must be considered [276]. This could lead to ethical criticism like that faced by biofuels due to competition with the food industry [277].

	Liquid hydrogen	Methanol	Ammonia	Hydrogen gas
Properties	Gas at atmospheric conditions	Liquid at atmospheric conditions	Gas at atmospheric conditions	Gas at atmospheric conditions
	Low volumetric hydrogen content	High volumetric hydrogen content	Highest volumetric hydrogen content	Lowest volumetric hydrogen content
Production	Liquefaction η of 40-60% Extra catalyst for ortho-para conversion Lowest energy to extract hydrogen	Hydrogenation η of 50-60% Production via CO_2 hydrogenation method High energy to extract hydrogen	Haber Bosch η of 40-60% Production via Haber-Bosch process Highest energy to extract hydrogen	Lowest energy to extract hydrogen
Storage and transport	Requires cryogenic temperatures (-253 °C) Boil-off losses occur during storage Transport by ship, truck	Does not need any refrigeration or pressurization Various transport and distribution options (ship, pipeline, truck and rail)	Requires to be cooled down (-33 °C) or pressurized (8.6 bar) Various transport and distribution options (ship, pipeline, truck and rail)	Requires to be pressurized (200-700 bar) Various transport and distribution options (pipeline and truck)
Emission	No emissions of CO_2 and NO_x emissions associated with the process	Possible to have low CO_2 emissions associated with the process	Possible to have low NO_x emissions associated with the process	No emissions associated with the process
Safety	Large flammability range in air No smell or flame visibility Autoignition at 520°C	Large flammability range in air No smell or flame visibility Autoignition at 440°C	Large flammability range in air Strong smell Autoignition at 650°C	Large flammability range in air No smell or flame visibility Autoignition H2 at 520°C
Toxicity	Not toxic	Toxic	Highly toxic	Not toxic
Cost	LCO_{LH2} 1.5-2.5 \$/kg_{LH2}	LCO_{CH3OH} 630-1130\$/t_{CH3OH}	LCO_{NH3} 2.4\$ /kg_{NH3}	LCO_{H2} 2-10 \$/kg_{H2}
Water use	15 t_{H2O}/t_{H2}	1.7 t_{H2O}/t_{CH3OH}	1.6 t_{H2O}/t_{NH3}	9 t_{H2O}/t_{H2}
Infrastructure	Commercially available	Commercially available	Commercially available	Commercially available

Figure 5.19. Comparison of green liquid hydrogen, methanol, ammonia and hydrogen gas *[64]*

5.4. Decision matrix

Four Power-to-X alternatives are compared with multi criteria decision making tools: Power-to-Hydrogen gas, Power-to-Liquid hydrogen, Power-to-Ammonia, and Power-to-Methanol. The four alternatives are evaluated using fifteen criteria. The storage conditions are evaluated based on temperature and pressure, while safety is assessed according to toxicity and explosion limits in air. The most important parameters in the weighting system are the levelized cost of production for any of the four substances, CO_2 emissions, and infrastructure.

The production of ammonia, methanol, and hydrogen used in the chemical, metallurgical, and agricultural sectors to an alternative production by using green hydrogen for their synthesis is evaluated in this research. The conversion of these substances back to electricity (the so-called Power-to-Power) might not be economically and technically meaningful, and it is far from achieving a TRL of 8-9 in the near future.

It is crucial to assess the storage conditions for temperature and pressure separately. While methanol and gas hydrogen can be stored at ambient temperature, liquid hydrogen, and methanol can be stored at ambient pressure. Consequently, methanol is the easiest substance to store out of the assessed alternatives. Based on specific energy use, hydrogen gas is the most favorable option, with ammonia following closely, while liquid hydrogen has the highest energy use during production.

Methanol and ammonia have comparable levelized costs of production, with ammonia being slightly more expensive, while liquid hydrogen is the costliest. However, green hydrogen gas has the lowest levelized cost of production since all four alternatives require green hydrogen production. The infrastructure cost for storing methanol is lower than for LH_2, given that methanol is a liquid at atmospheric temperature and pressure.

All three alternatives are regarded as green solutions, with nearly zero emissions under appropriate process conditions. Nonetheless, carbon capture storage technologies cannot prevent the release of approximately 1 kg_{CO2}/kg_{H2} [137]. Power-to-Ammonia is the most developed option, while methanol via hydrogenation is still being enhanced in terms of technology readiness level. Infrastructure already exists for all processes. Ammonia has the highest volumetric hydrogen density, while gas hydrogen has the lowest. Methanol is the safest alternative regarding explosion limits in the air, whereas hydrogen (liquid and gas) poses the highest risk. Ammonia is the most toxic among the options.

As already explained in Figure 5.18, ammonia is the best solution from a volumetric hydrogen density point of view, while gas hydrogen is the worst. Finally, from the safety point of view, the explosion limits in the air are considered, and the best option is methanol, while the worst one is hydrogen (liquid and gas). Ammonia is the most toxic substance among alternatives.

From a technology readiness level viewpoint, Power-to-Ammonia option is the more developed since ammonia is produced based on the Haber-Bosch process, while methanol via hydrogenation is still being improved. Infrastructure exists for all the processes, and that is one of the advantages of these solutions. However, currently, transportation via truck is more frequent for ammonia, followed by methanol, and finally, liquid hydrogen cryogenic truck. The IEA does not consider any category for the large-scale hydrogen regasification process in their latest report about TRL for technologies relevant to the net-zero emissions pathway. A TRL of 5 for the hydrogen regasification technology on a large-scale is recommended in this thesis.

As explained in Chapter 4, the decision matrix was analyzed with three MCDM tools and two weighting factor methods for a total of six cases (as shown in Table 4.13). The MCDM methods are the Weighting Sum Model, Technique for Order Preference by Similarity to Ideal Solution, and the Weighted Aggregated Sum Product Assessment. Additionally, the weighting factors have been selected for each parameter and are calculated according to the Analytic Hierarchy Process, and weighting factors that are subjective to the criteria of the author. The summary of the results of the four Power-to-X alternatives compared here for the six methodologies is presented in Figure 5.20. Ammonia is, in five of the six cases, the best solution for the selected study case in Germany, and liquid hydrogen is the least advantageous in five of the six calculations. The three options that applied AHP for the weighting factors present ammonia as the best solution for the study case. The options with subjective weighting factors have in common that the three rank liquid hydrogen as the worst Power-to-X solution for Germany. The results of each methodology are presented and discussed below.

The National Hydrogen Strategy in Germany contemplates a rapid penetration of hydrogen in the power sector, industry, and transport sectors to achieve the decarbonization of the country. The ports of Germany are in the north, and most of the industry is located in the south. Therefore, besides the transportation of the imported green hydrogen to the country, the internal transport of hydrogen produced or imported from north Germany to the southern part of the country must be taken into account.

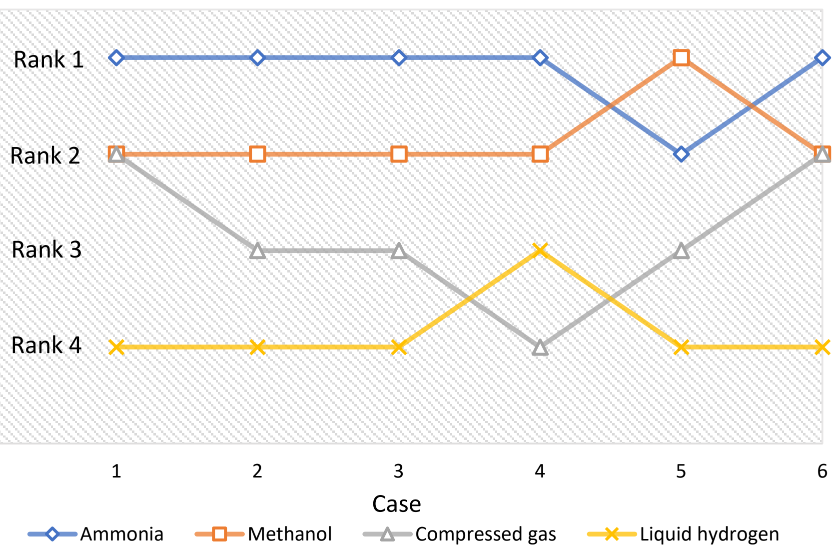


Figure 5.20. Rank of the four Power-to-X alternatives compared in this thesis using six combinations of methodologies

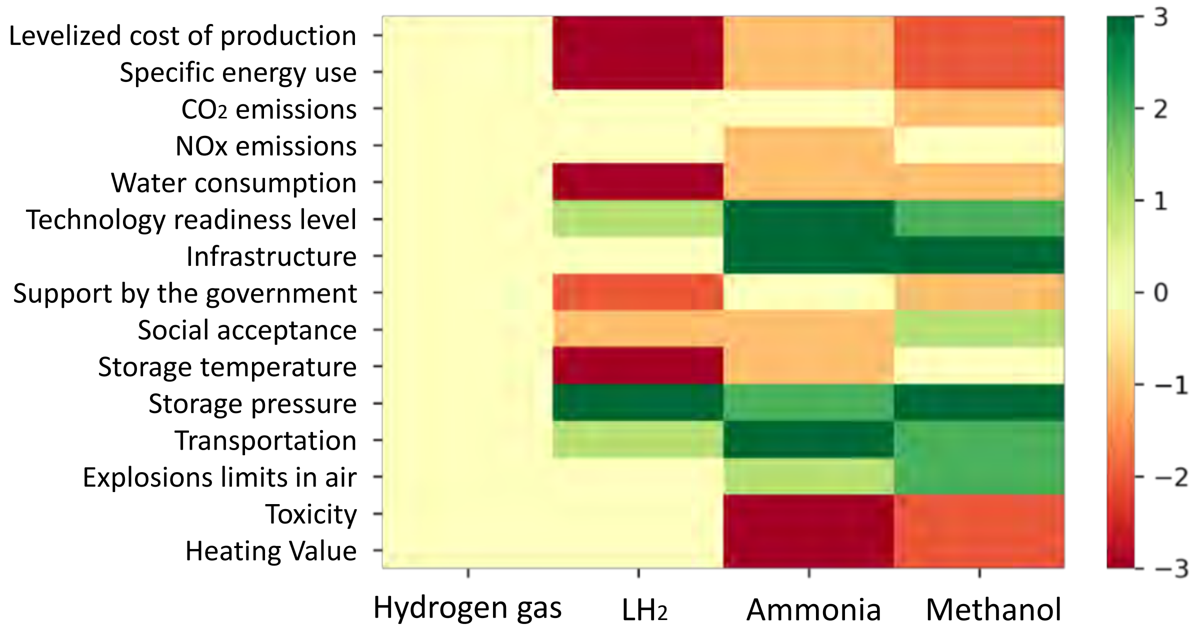


Figure 5.21. Decision matrix comparative heatmap of the four PtX technologies compared in this analysis using hydrogen gas, liquid hydrogen, ammonia, and methanol *[64]*

The heatmap of the first Case, applying the Weighting Sum Model and the Analytic Hierarchy Process, is presented in Figure 5.21. The heatmap provides a graphical comparison of the results, in yellow indicating the same results as the base case, greens denoting better results than the base case, and reds indicating worse results than the base case. The heatmap has been produced only for Case 1.

In Case 1, before weighting factors were applied, methanol was the most advantageous alternative among the four. Nevertheless, after the weighting factors were considered, Power-to-Ammonia had the highest score for transporting green hydrogen from North to South Germany, closely followed by Power-to-Methanol and Power-to-Hydrogen gas. Power-to-Liquid hydrogen was the least favorable for the country, as presented in Table 5.20. It is important to analyze and evaluate each case or country with pertinent parameters.

The consistency ratio calculated corresponds to 0.08 < 1.59 (Random Index (R.I.) for 15 criteria). Therefore, it is valid to assume that the metrics are reasonably consistent.

In Case 2, applying the Weighting Sum Model and the criteria of the author for the weighting method, the results changed for the second best solution and the third best solution. The results of the second Case are summarized in Table 5.21.

The Technique for Order Preference by Similarity to Ideal Solution and the author's criteria for the weighting factor is applied in Case 3. The categorization of the criteria and the normalized weighted matrix is presented in Table 5.22.

Table 5.20. Decision matrix comparison of the four Power-to-X technologies of Case 1

			Preliminary				Final		
Criteria		**Base case H_2 (g)**	**LH_2**	**Ammonia**	**Methanol**	**Weight factor**	**LH_2**	**Ammonia**	**Methanol**
Cost of production	Levelized cost of production	0	-3	-1	-2	14%	-0.43	-0.14	-0.28
	Specific energy use	0	-3	-1	-2	9%	-0.26	-0.09	-0.18
Emissions	CO_2	0	0	0	-1	14%	0.00	0.00	-0.14
	NOx	0	0	-1	0	2%	0.00	-0.02	0.00
Water use		0	-3	-1	-1	3%	-0.08	-0.03	-0.03
Technological Readiness Level		0	1	3	2	9%	0.09	0.28	0.19
Infrastructure		0	0	3	3	8%	0.00	0.24	0.24
Support by government		0	-2	0	-1	8%	-0.16	0.00	-0.08
Social acceptance		0	-1	-1	1	8%	-0.08	-0.08	0.08
Storage	Temperature	0	-3	-1	0	4%	-0.12	-0.04	0.00
	Pressure	0	3	2	3	4%	0.12	0.08	0.12
Transportation		0	1	3	2	8%	0.08	0.24	0.16
Safety	Explosion limits in air	0	0	1	2	2%	0.00	0.02	0.04
	Toxicity	0	0	-3	-2	3%	0.00	-0.08	-0.06
Heating Value		0	0	-3	-2	3%	0.00	-0.10	-0.07
Total		0	-10	0	2	100%	-0.84	**0.27**	0.00

Table 5.21. Decision matrix comparison of the four Power-to-X technologies of Case 2

Criteria		Base case	Preliminary				Final		
		H$_2$ (g)	**LH$_2$**	**Ammonia**	**Methanol**	**Weight factor**	**LH$_2$**	**Ammonia**	**Methanol**
Cost of production	Levelized cost of production	0	-3	-1	-2	12%	-0.36	-0.12	-0.24
	Specific energy use	0	-3	-1	-2	5%	-0.15	-0.05	-0.10
Emissions	CO_2	0	0	0	-1	8%	0.00	0.00	-0.08
	NOx	0	0	-1	0	5%	0.00	-0.05	0.00
Water use		0	-3	-1	-1	6%	-0.18	-0.06	-0.06
Technological Readiness Level		0	1	3	2	6%	0.06	0.18	0.12
Infrastructure		0	0	3	3	10%	0.00	0.30	0.30
Support by government		0	-2	0	-1	6%	-0.12	0.00	-0.06
Social acceptance		0	-1	-1	1	6%	-0.06	-0.06	0.06
Storage	Temperature	0	-3	-1	0	5%	-0.15	-0.05	0.00
	Pressure	0	3	2	3	5%	0.15	0.10	0.15
Transportation		0	1	3	2	10%	0.10	0.30	0.20
Safety	Explosion limits in air	0	0	1	2	5%	0.00	0.05	0.10
	Toxicity	0	0	-3	-2	6%	0.00	-0.18	-0.12
Heating Value		0	0	-3	-2	5%	0.00	-0.15	-0.10
Total		0	-10	0	2		-0.71	**0.21**	0.17

Table 5.22. Normalized decision matrix comparison of the four Power-to-X technologies of Case 3

		Preliminary					Normalized weighted matrix			
Criteria		**H_2 (g)**	**LH_2**	**Ammonia**	**Methanol**	**Weight factor**	**H_2 (g)**	**LH_2**	**Ammonia**	**Methanol**
Cost of production	Levelized cost of production	4	1	3	2	12%	0.088	0.022	0.066	0.044
	Specific energy use	4	1	3	2	5%	0.037	0.009	0.027	0.018
Emissions	CO_2	5	5	5	4	8%	0.042	0.042	0.042	0.034
	NOx	5	5	3	5	5%	0.027	0.027	0.016	0.027
Water use		4	1	3	3	6%	0.041	0.010	0.030	0.030
Technological Readiness Level		2	3	5	4	6%	0.016	0.024	0.041	0.033
Infrastructure		2	2	5	5	10%	0.026	0.026	0.066	0.066
Support by government		4	2	4	3	6%	0.036	0.018	0.036	0.027
Social acceptance		3	2	2	4	6%	0.031	0.021	0.021	0.042
Storage	Temperature	5	2	4	5	5%	0.030	0.012	0.024	0.030
	Pressure	2	5	4	5	5%	0.012	0.030	0.024	0.030
Transportation		1	2	5	4	10%	0.015	0.029	0.074	0.059
Safety	Explosion limits in air	1	1	3	4	5%	0.010	0.010	0.029	0.038
	Toxicity	4	4	1	3	6%	0.037	0.037	0.009	0.028
Heating Value		5	5	2	3	5%	0.031	0.031	0.013	0.019

Table 5.23. Ideal best and ideal worst for each criterion required for the TOPSIS methodology in Case 3

Criteria	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Ideal best	0.088	0.037	0.042	0.027	0.041	0.041	0.066	0.036	0.042	0.030	0.030	0.074	0.038	0.037	0.031
Ideal worst	0.022	0.009	0.034	0.016	0.010	0.016	0.026	0.018	0.021	0.012	0.012	0.015	0.010	0.009	0.013

Table 5.24. Rank of the four Power-to-X technologies for Case 3

Alternative	H_2 (g)	LH_2	Ammonia	Methanol
Euclidean distance from ideal best, S_i^+	0.083	0.108	0.050	0.055
Euclidean distance from ideal worst, S_i^-	0.090	0.044	0.097	0.085
Performance score, P_i	0.520	0.289	0.658	0.607
Rank	**3**	**4**	**1**	**2**

The ideal best and ideal worst for each criterion are required in the TOPSIS methodology to find the Euclidean distance between two points. The ideal values for each criterion are presented in Table 5.23. The corresponding number to each criterion is found in Table 4.12.

The rank of the PtX alternatives, according to the performance score, is presented in Table 5.24. The same best and worst alternative, as Cases 1 and 2 are obtained, ammonia is the best solution and liquid hydrogen is the worst Power-to-X option for Germany. The ranking of the four results of Case 3 coincides with those of Case 2. Both apply the weighting factor selected by the author. Case 4 also uses the TOPSIS approach with the APH weighting method. The preliminary decision matrix is the same as shown in Table 5.22.

The normalized values and the ideal best and ideal worst for each criterion are shown in Table 5.25. The rank of the alternatives and the performance score are presented in Table 5.26. For this case, the best solution is ammonia, and the worst energy vector would be hydrogen in gas form. This is the only option in which liquid hydrogen is not the worst one, but the third option. Methanol is the second best option.

The decision matrix applied in Case 5 is calculated with the Weighted Aggregated Sum Product Assessment methodology, which is the combination of the Weighting Sum Model and Weighting Product Model. The weighting factors are selected according to the criteria of the author. First, for the Weighting Sum Model, the decision matrix applied in Case 3 (Table 5.22) is used to calculate the preference score and rank the alternatives for the WSM, as shown in Table 5.27.

For the second part of the methodology, the decision matrix according to the WPM is calculated, and the second performance score is calculated. The result from the WPM has a different rank, where methanol is the best solution, as presented in Table 5.28.

Finally, both methods, WSM and WPM are combined, and the final score is obtained. For this case, methanol still is the best solution, followed by ammonia, compressed gas, and liquid hydrogen, as presented in Table 5.29.

Finally, Case 6 applies the Weighted Aggregated Sum Product Assessment and the Analytic Hierarchy Process for the weighting factor. For the WSM, the normalized decision matrix is the same one as the fourth Case (Table 5.25), and the rank of the four alternatives is shown in Table 5.30. For the WPM, the decision matrix and performance score change resulting in different ranks, where the hydrogen gas and methanol are not in the same position, as shown in Table 5.31.

Finally, both methods, WSM and WPM are combined, and the final score is obtained. For this case, green methanol is the best solution, followed by ammonia, compressed gas, and liquid hydrogen, as presented in Table 5.32.

Table 5.25. Ideal best and ideal worst for each criterion required for TOPSIS in Case 4

Criteria		**H_2 (g)**	**LH_2**	**NH_3**	**CH_3OH**	**Ideal best, V_j^+**	**Ideal worst, V_j^-**
Cost of production	Levelized cost of production	0.104	0.026	0.078	0.052	0.104	0.026
	Specific energy use	0.064	0.016	0.048	0.032	0.064	0.016
Emissions	CO_2	0.074	0.074	0.074	0.059	0.074	0.059
	NOx	0.013	0.013	0.008	0.013	0.013	0.008
Water use		0.019	0.005	0.014	0.014	0.019	0.005
Technological Readiness Level		0.026	0.039	0.065	0.052	0.065	0.026
Infrastructure		0.021	0.021	0.052	0.052	0.052	0.021
Support by government		0.046	0.023	0.046	0.035	0.046	0.023
Social acceptance		0.044	0.029	0.029	0.058	0.058	0.029
Storage	Temperature	0.023	0.009	0.018	0.023	0.023	0.009
	Pressure	0.009	0.023	0.018	0.023	0.023	0.009
Transportation		0.012	0.024	0.059	0.047	0.059	0.012
Safety	Explosion limits in air	0.004	0.004	0.012	0.016	0.016	0.004
	Toxicity	0.017	0.017	0.004	0.013	0.017	0.004
Heating Value		0.022	0.022	0.009	0.013	0.022	0.009

Table 5.26. Rank of the four Power-to-X technologies for Case 4

Alternative	**H_2 (g)**	**LH_2**	**Ammonia**	**Methanol**
Euclidean distance from ideal best, S_i^+	0.078	0.052	0.048	0.047
Euclidean distance from ideal worst, S_i^-	0.091	0.061	0.076	0.063
Performance score, P_i	0.536	0.543	0.613	0.572
Rank	**4**	**3**	**1**	**2**

Table 5.27. Rank of the four Power-to-X technologies in Case 5 and the Weighting Sum Model

Alternative	**H_2 (g)**	**LH_2**	**Ammonia**	**Methanol**
Preference score, Q_i^1	0.48	0.35	0.52	0.52
Rank	3	4	1	1

Table 5.28. Rank of the four Power-to-X technologies in Case 5 and the Weighting Product Model

Criteria		**H_2 (g)**	**LH_2**	**Ammonia**	**Methanol**
Cost of production	Levelized cost of production	0.963	0.815	0.930	0.886
	Specific energy use	0.984	0.918	0.970	0.951
Emissions	CO_2	0.950	0.950	0.950	0.933
	NOx	0.970	0.970	0.946	0.970
Water use		0.977	0.899	0.960	0.960
Technological Readiness Level		0.925	0.948	0.977	0.964
Infrastructure		0.875	0.875	0.959	0.959
Support by government		0.969	0.930	0.969	0.953
Social acceptance		0.962	0.939	0.939	0.979
Storage	Temperature	0.975	0.931	0.964	0.975
	Pressure	0.931	0.975	0.964	0.975
Transportation		0.826	0.885	0.970	0.949
Safety	Explosion limits in air	0.921	0.921	0.973	0.987
	Toxicity	0.971	0.971	0.894	0.955
Heating Value		0.977	0.977	0.933	0.953
Preference score, Q_i^2		0.422	0.315	0.485	0.510
Rank		**3**	**4**	**2**	**1**

Table 5.29. Rank of the four Power-to-X technologies for Case 5 for WASPAS approach

	$\boldsymbol{Q_i^1}$	$\boldsymbol{Q_i^2}$	$\boldsymbol{Q_i^{Tot}}$	**Rank**
H_2 (g)	0.48	0.42	0.45	3
LH_2	0.35	0.32	0.33	4
Ammonia	0.52	0.49	0.50	2
Methanol	0.52	0.51	0.52	1

Table 5.30. Rank of the four Power-to-X technologies for Case 6 and the Weighting Sum Model

Alternative	**H_2 (g)**	**LH_2**	**Ammonia**	**Methanol**
Preference score, Q_i^1	0.50	0.35	0.54	0.50
Rank	2	4	1	2

Table 5.31. Rank of the four Power-to-X technologies in Case 6 and the Weighting Product Model

Criteria		**H_2 (g)**	**LH_2**	**Ammonia**	**Methanol**
Cost of production	Levelized cost of production	0.956	0.786	0.918	0.867
	Specific energy use	0.973	0.861	0.948	0.915
Emissions	CO_2	0.912	0.912	0.912	0.884
	NOx	0.985	0.985	0.973	0.985
Water use		0.989	0.952	0.981	0.981
Technological Readiness Level		0.884	0.918	0.964	0.944
Infrastructure		0.900	0.900	0.967	0.967
Support by government		0.960	0.910	0.960	0.939
Social acceptance		0.947	0.915	0.915	0.970
Storage	Temperature	0.980	0.946	0.972	0.980
	Pressure	0.946	0.980	0.972	0.980
Transportation		0.858	0.907	0.976	0.959
Safety	Explosion limits in air	0.966	0.966	0.988	0.994
	Toxicity	0.987	0.987	0.949	0.979
Heating Value		0.984	0.984	0.954	0.967
Preference score, Q_i^2		0.447	0.315	0.513	0.489
Rank		**3**	**4**	**1**	**2**

Table 5.32. Rank of the four Power-to-X technologies in Case 6 for the WASPAS approach

	Q_i^1	Q_i^2	Q_i^{Tot}	**Rank**
H_2 (g)	0.50	0.45	0.27	2
LH_2	0.35	0.31	0.19	4
Ammonia	0.54	0.51	0.29	1
Methanol	0.50	0.49	0.27	2

Chapter 6. Conclusions and recommendations

A comprehensive evaluation of the large-scale hydrogen economy has been presented in this thesis. The complete green liquid hydrogen path, from gas and liquid hydrogen production to reconversion to hydrogen gas, was extensively evaluated from an energetic, exergetic, and economic point of view. In total, four alternatives for hydrogen transportation and storage were compared. The Power-to-X options discussed in this document are Power-to-Liquid hydrogen, Power-to-Ammonia, Power-to-Methanol, and Power-to-Hydrogen gas. The state of the art, properties, challenges, recent developments, and political will to implement the options were assessed. The relevant parameters for the comparison were selected, and six decision matrices were applied to a study case country, Germany. The conclusions and recommendations of this thesis are divided into five parts.

1. The exergetic analysis of the liquid hydrogen chain:

- First, for green hydrogen production, a 100 MW PEM electrolyzer was considered. The exergy efficiency calculated was 60% for a specific energy use of 5 kWh/Nm^3_{H2}.
- The exergy destruction of the electrolyzer is primarily due to the chemical reactions that occur in the cathode and anode.
- For liquid hydrogen production, the exergetic efficiency was 42% for a specific energy use of 8.1 kWh/kg_{H2}.
- The liquefier had total exergy destruction of 9.3 MW, and the compressors represented the highest share of the total exergy destruction.
- For the regasification of hydrogen, the exergy efficiency was 62% (scenario 2).
- The thermal exergy of the liquid hydrogen stream is transformed into mechanical exergy after regasification.

2. The economic analysis of the liquid hydrogen chain:

- For green hydrogen production, the main cost corresponds to the electricity required to run the electrolyzer (68% of the total cost).
- A levelized cost of green hydrogen of 5.5 US$/$kg_{H2}$ and 8.8 US$/$kg_{H2}$ was calculated for an electricity price of 50 US$/MWh and 110 US$/MWh, respectively.
- A total capital investment of 215 million US$ for the electrolyzer stacks was estimated.
- For the liquid hydrogen production, the turbomachinery dominates the Bare Module Cost of the liquefaction system (68%).
- A specific levelized cost for the liquefaction of hydrogen of 1.7 US$/kg was calculated.
- The detailed economic analysis of a hydrogen regasification cogeneration plant was assessed. Two scenarios were considered a) using natural gas as fuel for the open gas turbine and b) using a mixture of natural gas (70%) and hydrogen (30%) as fuel for the open gas turbine. The total revenue requirement of the hydrogen regasification plant

corresponds to 227.7 million US$ for the first scenario and almost double the amount for the second scenario, using hydrogen as fuel, 444.1 million US$.

- The expander of the open gas turbine system has the highest equipment cost (23%), and the open gas turbine accounts for 54% of the total cost of the system.
- Finally, the hydrogen regasification cost, with only natural gas as fuel, was calculated in a range of 1.11 US/kg_{H2}$ – 0.70 US/kg_{H2}$, according to the operating hours from 2600 h/a to full-time operation, respectively.
- Adding the cost of the liquid hydrogen, the total cost of the regasified green hydrogen, excluding the transport cost, amounts to 11.2 US/kg_{H2}$ for full-time operation for an electricity price of 110 US$/MWh.
- The average rate of return of the hydrogen regasification plant corresponds to 1.84%. The payback period of the project of over 17 years is very close to the lifetime of the project considered here, of 20 years. The internal rate of return of the project corresponds to only 1.3%. The project is not economically attractive without external incentives.

The large-scale LH_2 regasification has not been extensively reported yet. It is recommended to conduct the exergoeconomic analysis and optimize the evaluated cogeneration system.

3. The configurations proposed for the regasification of hydrogen.

The large-scale regasification of liquid hydrogen discussed in this thesis consists of three sub-systems to regasify hydrogen and produce power. The sub-system that operates at higher temperatures corresponds to an open gas turbine system (LMS100 GE). The middle sub-system is the closed-cycle gas turbine with helium as the working fluid. Finally, the lowest temperature sub-system corresponds to the regasification of hydrogen.

- Six scenarios were compared with and without a recuperator in the intermediate cycle. The pressure of this intermediate cycle before entering the helium compressor was also evaluated; 2.8 bar in three scenarios and 12 bar in the other three scenarios.
- The cryogenic temperature of the liquid hydrogen represents a potential to utilize the exergy transferred when the hydrogen is regasified of 20.4 MW that would otherwise be destroyed.
- The efficiency of the regasification plant increases by 5%-points (from 57% to 62%) when a recuperator is used; however, the ratio of mass flow of helium/liquid hydrogen increases from 0.67 to 2.65 without the recuperator.

It is recommended to improve the configuration by preheating the incoming air of the open gas turbine and increasing the temperature of the outgoing hydrogen stream. A third intermediate cycle would be needed for this purpose due to security reasons and temperature differences. It is also recommended for the optimization of the plant to decrease the temperature of the exhaust gases closer to the environmental temperature.

4. Hydrogen “colors”

In this thesis, the primary routes of hydrogen production and their corresponding color designations, collectively referred to as the "hydrogen rainbow," are outlined. Detailed explanations are provided for the hydrogen feedstock, production process, and associated CO_2 emissions for each color: green, blue, gray, black, brown, yellow, pink, red, and orange hydrogen. It should be noted that regardless of the assigned color, hydrogen itself remains colorless.

- The most recognized colors to refer to hydrogen are green, gray, and blue.
- The colors with the most confusion and different definitions according to the source of information are yellow, pink, orange, purple, and red.
- By May 2023, there was no standardized classification for the so-called “hydrogen rainbow”, and the need to identify between the different pathways is growing. Especially the comparison of the carbon intensity of each process becomes very relevant in the current context, where decarbonization is the goal.
- The main interest for the next decade lies in green hydrogen; however, many countries support blue or turquoise hydrogen for the transition period, especially the top exporters countries of fossil fuels.
- The cost of electricity and the capital cost of the electrolyzers are the main parameters that affect the price of orange and green hydrogen.
- Quick escalation of the electrolyzer production will drive down the cost of green, orange, and pink hydrogen.

Continued support from the political sphere is crucial for the realization of planned projects for developing a hydrogen economy. Nevertheless, the use of a "hydrogen rainbow" color classification system can be confusing and may even divert attention from the important purpose. For color classification to be beneficial, it requires the widespread adoption of a standardized and widely accepted color code. Otherwise, it could complicate communication and hinder the policy-making process rather than aid in the selection of the appropriate pathway. The challenges facing the hydrogen economy include cost reduction, the current inadequacy of production infrastructure to meet future demand for green hydrogen, and the transportation of hydrogen.

5. The decision matrix

This thesis focuses on comparing four Power-to-X options: Power-to-Liquid hydrogen, Power-to-Ammonia, Power-to-Methanol, and Power-to-Hydrogen Gas. The comparison is based on hydrogen generated through water electrolysis and powered exclusively by renewable energy sources. The overall production costs of these options are affected by the higher expense of renewable electricity, in contrast to the conventional production methods that utilize fossil fuels to produce gaseous hydrogen, liquid hydrogen, ammonia, and methanol.

Numerous economic, technical, and environmental factors were taken into account when conducting the comparison. These factors include storage temperature and pressure, production costs, emissions, technology readiness level, available infrastructure, volumetric hydrogen density, safety, water usage, and the general acceptance of the technology.

- Power-to-Ammonia is, in five of the six decision matrices compared in the results, the best solution for the study case, and liquid hydrogen is the least advantageous in five of the six calculations. The three options applying the Analytic Hierarchy Process for the weighting factors present ammonia as the best solution for the study case.
- The three options with subjective weighting factors have in common the ranking of liquid hydrogen as the worst Power-to-X solution for Germany.
- There is still uncertainty about which hydrogen transportation option should be developed to satisfy the demand of each country. Every country should be analyzed individually.
- Adopting new policies and regulations as part of the German Hydrogen Plan will decrease the costs of "green production" in the future.

It is important to note that all proposed solutions are technically viable and should be further investigated. With adequate political support, the implementation of carbon pricing, and an increase in demand, Power-to-X technology holds the potential to become economically feasible. Hydrogen could play a crucial role as an energy vector in achieving climate goals.

Although this thesis didn't examine the utilization of nuclear energy specifically for generating pink and red hydrogen, it becomes evident that achieving the significant electricity demand for complete decarbonization in the present decade, without the emissions of carbon dioxide, would pose a considerable challenge without incorporating hydrogen production from nuclear power generation.

Furthermore, this thesis assumes the availability of large-scale green hydrogen production in the near future. However, an important question arises regarding the decarbonization perspective when renewable electricity is used to produce hydrogen while fossil fuels continue to be utilized for electricity generation in the same region. Using the same fossil fuels directly in a process or for electricity generation would result in lower overall CO_2 emissions compared to using hydrogen or the derived green substances. Nevertheless, hydrogen utilization for energy storage becomes necessary as renewable electricity production achieves much higher shares than at present.

The production of clean hydrogen presents various challenges, including the expansion of renewable energy sources, which require significant capital investments, particularly in developing countries, and are subject to political and social considerations.

Furthermore, there will be a competitive environment among various decarbonization alternatives within the energy sector. Given the many challenges, it is a reasonable conclusion that the adoption of the hydrogen economy might experience postponement in contrast to the timelines proposed in present studies. This delay is attributed to the requirement for substantial surplus green electricity for effective decarbonization. Nevertheless, the implementation of a suitable carbon-pricing strategy via political decisions would unquestionably accelerate this progress.

References

[1] UNEP and WMO, "Climate Change: The IPCC 1990 and 1992 Assessments," Canada, 1992.

[2] H. Pörtner, D. Roberts, M. Tignor, E. Poloczanska, Mintenbeck, K. A. Alegría, M. Craig, S. Langsdorf, S. Löschke, V. Möller, A. Okem and B. Rama, "IPCC, 2022: Climate Change 2022: Impacts, Adaptation, and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change," Cambridge University Press., Cambridge, UK and New York, 2022.

[3] M. Sterner and I. Stadler, Handbook of Energy Storage: Demand, Technologies, Integration, Regensburg: Springer, 2019.

[4] S. Hamdy, Cryogenic Energy Storage Systems: An Exergy-based Evaluation and Optimization, Berlin: Technische Universität Berlin, 2019.

[5] IRENA, "Hydrogen from renewable power: Technology outlook for the energy transition," International Renewable Energy Agency, Abu Dhabi, 2018.

[6] IEA, "The Future of Hydrogen: Seizing today’s opportunities," International Energy Agency, 2019.

[7] IRENA and AEA, "Innovation Outlook: Renewable Ammonia," International Renewable Energy Agency & Ammonia Energy Association, Abu Dhabi & Brooklyn, 2022.

[8] IEA, "Ammonia Technology Roadmap," International Energy Agency, Paris , 2021.

[9] IRENA and METHANOL INSTITUTE, "Innovation Outlook : Renewable Methanol," International Renewable Energy Agency, Abu Dhabi, 2021.

[10] "Green hydrogen and Power-to-X products," Federal Ministry for Economic Cooperation and Development, 2021. [Online]. Available: https://www.bmz.de/en/development-policy/green-hydrogen. [Accessed 2021 09 17].

[11] IEA, "Global Hydrogen Review," International Energy Agency, Paris, 2021.

[12] IEA, "The Covid-19 Crisis and Clean Energy Progress, IEA," International Energy Agency, Paris, 2020.

[13] IEA, "Energy Technology Perspectives 2020," International Energy Agency, Paris, 2020.

[14] BloombergNEF, "Hydrogen Economy Outlook, Key messages," Bloomberg Finance L.P., 2020.

[15] IRENA, "Hydrogen: A Renewable Energy Perspective," International Renewable Energy Agency, Abu Dhabi, 2019.

[16] A. Ajanovic, M. Sayer and R. Haas, "The economics and the environmental benignity of different colors of hydrogen," *International Journal of Hydrogen Energy,* vol. 47, no. 57, pp. 24136-24154, 2022.

[17] IEA, "World Energy Outlook," International Energy Agency, Paris, 2022.

[18] IEA, "Global Hydrogen Review," IEA, Paris, 2022.

[19] Joint Fuel Cells and Hydrogen, "Hydrogen Roadmap Europe," Publications Office of the European Union, Belgium, 2019.

[20] Hydrogen and Fuel Cell Strategy Council, "The Strategic Road Map for Hydrogen and Fuel Cells - Industry-academia-government action plan to realize a “Hydrogen Society” -," Japan, 2019.

[21] IEA, "Hydrogen patents for a clean energy future: A global trend analysis of innovation along hydrogen value chains," International Energy Agency, 2023.

[22] IEA, "World Energy Investment," Paris, 2021.

[23] J. Incer-Valverde, S. Hamdy, T. Morosuk and G. Tsatsaronis, "Improvement perspectives of cryogenics-based energy storage," *Renewable Energy,* vol. 169, pp. 629-640, 2021.

[24] IRENA, "Global Renewables Outlook: Energy transformation 2050," Abu Dabhi, 2021.

[25] R. H. Perry and D. W. Green, Perry's chemical engineers' handbook, New York: McGraw-Hill, 2008.

[26] M. Aziz, A. Wijayanta and A. Nandiyanto, "Ammonia as Effective Hydrogen Storage: A Review on Production, Storage and Utilization," *Energies,* vol. 13, p. 3062, 2020.

[27] H. Dagdougui, R. Sacile, C. Bersani and A. Ouammi, "Hydrogen Logistics: Safety and Risks Issues," in *Hydrogen Infrastructure for Energy Applications*, Academic Press, 2018, pp. 127-148.

[28] E. Papadis and G. Tsatsaronis, "Challenges in the Decarbonization of the Energy Sector," *Energy,* vol. 2015, p. 118025 , 2020.

[29] WEC, "Working Paper | Hydrogen on the Horizon: National Hydrogen Strategies," World Energy Council, London, 2021.

[30] A. Energiewende, "Making renewable hydrogen cost-competitive: Policy instruments for supporting green H_2. Conclusions drawn," Agora Energiewende, Berlin, 2021.

[31] R. Hage, R. Kombargi, S. Elborai and Y. Anouti, "The dawn of green hydrogen: Maintaining the GCC's edge in a decarbonized world," Strategy & PwC, 2020.

[32] B. Page, A. Al-Khowaiter, S. Bohlen, H. Heitkamp, K. Kaufmann, M. Dreyfus, A. Majumdar, N. Nakicenovic, A. Siemenski and N. Tanaka, "Blue Hydrogen," Global CCS Insitute, 2021.

[33] P. Schneider, "The colours of hydrogen," Ewe, [Online]. Available: https://www.ewe.com/en/shaping-the-future/hydrogen/the-colours-of-hydrogen. [Accessed 09 11 2022].

[34] S. Van de Riet and N. Bais, "A hydrogen rainbow is emerging, but which colors lead to the pot of gold?," Deloitte, [Online]. Available: https://www2.deloitte.com/nl/nl/pages/energy-resources-industrials/articles/hydrogen-rainbow.html. [Accessed 09 11 2022].

[35] S. Chandra, "What is the HYDROGEN RAINBOW?," 17 05 2021. [Online]. Available: https://www.linkedin.com/pulse/what-hydrogen-rainbow-sandeep-chandra/. [Accessed 09 11 2022].

[36] "WHAT IS THE HYDROGEN RAINBOW?," Cummins Inc., Global Power Technology Leader, 16 11 2021. [Online]. Available: https://www.cummins.com/news/2021/11/16/what-hydrogen-rainbow. [Accessed 09 11 2022].

[37] J. Callens, "The Renaissance of Nuclear Power to Accommodate Net-Zero by 2050: New Energy Outlook 2021," BloombergNEF, 04 11 2021. [Online]. Available: https://about.bnef.com/blog/the-renaissance-of-nuclear-power-to-accommodate-net-zero-by-2050-new-energy-outlook-2021/. [Accessed 09 11 2022].

[38] A. Willige, "Hydrogen rainbow: the colors of decarbonization," Mitsubishi Heavy Industry Group, 28 07 2022. [Online]. Available: https://spectra.mhi.com/hydrogen-rainbow-the-colors-of-decarbonization. [Accessed 09 11 2022].

[39] L. Pinkerton, "The Hydrogen Rainbow Is So 2021—It's Time to Get Over It," Power, 02 03 2022. [Online]. Available: https://www.powermag.com/blog/the-hydrogen-rainbow-is-so-2021-its-time-to-get-over-it/. [Accessed 09 11 2022].

[40] B. Williams, "What is yellow hydrogen?," Hydrogen Fuel News, 06 08 2022. [Online]. Available: https://www.hydrogenfuelnews.com/what-is-yellow-hydrogen/8552843/. [Accessed 09 11 2022].

[41] J. Dodgshun, "Hydrogen: Clearing Up the Colours," Enapter, 30 09 2020. [Online]. Available: https://www.enapter.com/newsroom/hydrogen-clearing-up-the-colours. [Accessed 09 11 2022].

[42] O. Olaniyi, J. Incer-Valverde, G. Tsatsaronis and T. Morosuk, "Exergetic and Economic Evaluation of Natural Gas/Hydrogen Blends for Power Generation," *Journal of Energy Resources Technology,* vol. 145, no. 6, pp. 1-16, 2023.

[43] A. Willige, "The colors of hydrogen: Expanding ways of decarbonization," Mitsubishi Heavy Industries Group, 28 07 2022. [Online]. Available: https://spectra.mhi.com/the-colors-of-hydrogen-expanding-ways-of-decarbonization. [Accessed 08 11 2022].

[44] J. Incer-Valverde, A. Korayem, G. Tsatsaronis and T. Morosuk, "“Colors” of hydrogen: Definitions and carbon intensity," *Energy Conversion and Management,* vol. 291, p. 117294, 2023.

[45] "Commission sets out rules for renewable hydrogen," European Commission, 13 02 2023. [Online]. Available: https://ec.europa.eu/commission/presscorner/detail/en/ip_23_594. [Accessed 14 05 2023].

[46] M. Dalton, "Europe Sets Rules for Producing Green Hydrogen," Spectra, 31 03 2023. [Online]. Available: https://spectra.mhi.com/partner-europe-sets-rules-for-producing-green-hydrogen?utm_source=newsletter&utm_medium=email&utm_campaign=spectra. [Accessed 20 04 2023].

[47] IEA, "Towards hydrogen definitions based on their emissions intensity," International Energy Agency, Paris, 2023.

[48] IEA, "Opportunities for Hydrogen Production with CCUS in China," International Energy Agency, Paris, 2022.

[49] "The 14th Five-Year Plan of the People’s Republic of China —Fostering High-Quality Development," Asian Development Bank, 06 2021. [Online]. Available: https://www.adb.org/publications/14th-five-year-plan-high-quality-development-prc. [Accessed 07 10 2021].

[50] Yuki, "China’s National Hydrogen Development Plan," Energy Iceberg, 06 04 2022. [Online]. Available: https://energyiceberg.com/national-hydrogen-development-plan/. [Accessed 26 04 2023].

[51] S. Takeda and H. C. A. Nam, "Low-carbon energy transition with the sun and forest: Solar-driven hydrogen production from biomass," *International Journal of Hydrogen Energy,* vol. 47, no. 58, pp. 24651-24668, 2022.

[52] A. Midilli, H. Kucuk, M. Haciosmanoglu, U. Akbulut and I. Dincer, "A review on converting plastic wastes into clean hydrogen via gasification for better sustainability," *International Journal of Energy Research,* vol. 46, no. 4, pp. 4001-4032, 2022.

[53] H. Qi, P. Cui, Z. Liu, Z. Xu, D. Yao, Y. Wang, Z. Zhu and S. Yang, "Conceptual design and comprehensive analysis for novel municipal sludge gasification-based hydrogen production via plasma gasifier," *Energy Conversion and Management,* vol. 245, p. 114635, 2021.

[54] J. Guo, Y. Zhang and A. Zavabeti, "Hydrogen production from the air," *Nat Commun.,* vol. 13, p. 5046, 2022.

[55] G. Gahleitner, "Hydrogen from renewable electricity: An international review of power-to-gas pilot plants for stationary applications," *International Journal of Hydrogen Energy,* vol. 38, pp. 2039-2061, 2013.

[56] M. Genovese, A. Schlüter, E. Scionti, F. Piraino, O. Corigliano and P. Fragiacomo, "Power-to-hydrogen and hydrogen-to-X energy systems for the industry of the future in Europe," *International Journal of Hydrogen Energy,* 2023.

[57] "The Government´s Strategy for POWER-TO-X," Danish Ministry of Climate, Energy and Utilities, Denmark, 2022.

[58] Federal Ministry of Education and Research, "Power-to-X in Germany : These industrial plants are already in operation today," Federal Ministry of Education and Research, 2021. [Online]. Available: https://www.kopernikus-projekte.de/en/projects/p2x/ptx_plants. [Accessed 19 09 2021].

[59] A. Wörner, "Zukünftige Speicher- und Flexibilitätsoptionen durch Power-to-X," in *Energie Speicher Symposium*, Stuttgart, 2014.

[60] P. Lund, J. Mikkola and J. Lindgren, "Review of energy system flexibility measures to enable high levels of variable renewable electricity," *Renewable and Sustainable Energy Reviews,* vol. 45, pp. 785-807, 2015.

[61] W. Leitner, "Power-To-X: Entering the Energy Transition with Kopernikus," RWTH Aachen University, 05 04 2016. [Online]. Available: https://www.rwth-aachen.de/go/id/kvyv/lidx/1. [Accessed 13 09 2021].

[62] R. Dickinson, "Power-to-Hydrogen and Hydrogen-to-X pathways:," in *14th International Conference on the European Energy Market (EEM)*, Dresden, 2017.

[63] Siemens AG, "What is Power-to-X?," Siemens AG, 2020-2021. [Online]. Available: https://www.siemens-energy.com/global/en/offerings/renewable-energy/hydrogen-

solutions.html?gclid=CjwKCAjw7fuJBhBdEiwA2lLMYRsSn0TMaVlBwwtBSRgT9Izz1xn7dkg3dOd1eOHye506u_Ezs6iz4hoCC1gQAvD_BwE. [Accessed 13 09 2021].

[64] J. Incer-Valverde, L. J. Patiño-Arévalo, G. Tsatsaronis and T. Morosuk, "Hydrogen-driven Power-to-X: State of the art and multicriteria evaluation of a study case," *Energy Conversion and Management,* vol. 266, p. 115814, 2022.

[65] N. Van Eck and L. Waltman, "Software survey: VOSviewer, a computer program for bibliometric mapping," *Scientometrics,* vol. 84, p. 523–538, 2010.

[66] M. Muron, G. Pawelec, S. Jackson and I. Yovchev, "Clean Hydrogen Monitor," Hydrogen Europ, 2022.

[67] B. Decourt, "Weaknesses and drivers for power-to-X diffusion in Europe. Insights from technological innovation system analysis," *International Journal of Hydrogen Energy,* vol. 44, pp. 17411-17430, 2019.

[68] B. Erlach, B. Lunz and M. Merzkirch, "Flexibility concepts for the German power supply in 2050," acatech – National Academy of Science and Engineering , Munich, 2016.

[69] M. Robinius, L. Welder, D. Severin, C. Mansilla, P. Lucchese, O. Tlili and J. Simon, "Power-to-hydrogen and hydrogen-to-X: Which markets? Which economic potential? Answers from the literature," in *14th International Conference on the European Energy Market (EEM)*, Dresden, 2017.

[70] Z. Chehade, C. Mansilla and P. Lucchese, "Review and analysis of demonstration projects on power-to-X pathways in the world," *International Journal of Hydrogen Energy,* vol. 44, pp. 27637-27655, 2019.

[71] "Launch of the world’s largest Power-to-Liquid Pilot plant," INERATEC, 04 10 2021. [Online]. Available: https://ineratec.de/en/launch-of-the-worlds-largest-power-to-liquid-pilot-plant/. [Accessed 09 11 2021].

[72] "Power-to-X in Germany : These industrial plants are already in operation today," Federal Ministry of Education and Research, 2021. [Online]. Available: https://www.kopernikus-projekte.de/en/projects/p2x/ptx_plants. [Accessed 09 11 2021].

[73] Kopernikus Project, "Power-to-X in Germany: These projects are already existing," [Online]. Available: https://www.kopernikus-projekte.de/en/projects/p2x/ptx_projects. [Accessed 1 08 2021].

[74] M. Mies, "How the Kopernicus project ENSURE is developing the power grid of the future," Federal Ministry of Education and Research, [Online]. Available: https://www.kopernikus-projekte.de/en/projects/ensure. [Accessed 08 02 2022].

[75] B. Fückel, "How the Kopernikus project P2X converts renewable electricity into plastics and fuels, gases and heat," Federal Ministry of Education and Research, [Online]. Available: https://www.kopernikus-projekte.de/en/projects/p2x. [Accessed 08 02 2022].

[76] M. Pützer, "How the Kopernicus project SynErgie helps industry match its electricity demand to the supply," Federal Ministry of Education and Research, [Online]. Available: https://www.kopernikus-projekte.de/en/projects/synergie. [Accessed 08 02 2022].

[77] "Kopernikus Projekte Ariadne," Federal Ministry of Education and Research, [Online]. Available: https://ariadneprojekt.de/. [Accessed 08 02 2022].

[78] Federal Ministry of Education and Research, "Kopernikus projekte," 2016. [Online]. Available: https://www.kopernikus-projekte.de. [Accessed 29 07 2021].

[79] H2Global Advisory GmbH, "H2Global Die Globale Energiwende gestalten," Bundesministerium für WIrtschaft und Energie, 06 2021. [Online]. Available: https://h2-global.de/. [Accessed 06 10 2021].

[80] "Minister Altmaier: “Making further progress on international market ramp-up for green hydrogen”," Federal Ministry for Economic Affairs and Energy, 14 06 2021. [Online]. Available: https://www.bmwi.de/Redaktion/EN/Pressemitteilungen/2021/06/20210614-new-funding-instrument-h2global-launched.html. [Accessed 06 10 2021].

[81] E. Terplan, "Steag realisiert Leuchtturm-Projekt zur Methanol-Synthese," gwf Gas + Energie, 2022. [Online]. Available: https://gwf-gas.de/maerkte-und-unternehmen/steag-realisiert-leuchtturm-projekt-zur-methanol-synthese/. [Accessed 17 02 2022].

[82] BMWi, "IPCEI Wasserstoff: Gemeinsam einen Europäischen Wasserstoffmarkt schaffen," 2021. [Online]. Available: https://www.bmwi.de/Redaktion/DE/Artikel/Energie/ipcei-wasserstoff.html. [Accessed 07 28 2021].

[83] A. Brandt and M. Pedack, "AMPRION," 2019. [Online]. Available: https://www.amprion.net/Netzjournal/Beitr%C3%A4ge-2019/Three-good-reasons-for-power-to-gas.html. [Accessed 20 03 2021].

[84] UNIPER, 19 07 2019. [Online]. Available: https://www.uniper.energy/news/uniper-and-its-partners-plan-a-large-facility-to-produce-and-store-green-hydrogen-in-saxony-anhalt. [Accessed 29 06 2021].

[85] "PtX Lab Lausitz delivering synthetic fuels from the laboratory to aviation and shipping," Federal Ministry for the Environment, Nature Conservation, Nuclear Safety and Consumer Protection, 02 03 2021. [Online]. Available:

https://www.bmuv.de/en/pressrelease/ptx-lab-lausitz-delivering-synthetic-fuels-from-the-laboratory-to-aviation-and-shipping/. [Accessed 03 02 2023].

[86] Forschungszentrum Jülich, "H2 Atlas Africa," Federal Ministry of Education and Research (BMBF), 2021. [Online]. Available: https://www.h2atlas.de/de/. [Accessed 28 04 2022].

[87] M. Bailey, "BP evaluating the establishment of a hydrogen hub in Germany," Chemical Engineering, 18 01 2023. [Online]. Available: https://www.chemengonline.com/bp-evaluating-the-establishment-of-a-hydrogen-hub-in-germany/?oly_enc_id=8797H8308467A5S. [Accessed 01 02 2023].

[88] Deutsche Windguard GmbH, "Deutsche Windguard," 2020. [Online]. Available: https://www.windguard.com/. [Accessed 02 03 2021].

[89] BMWi, "Die Nationale Wasserstoffstrategie," Bundesministerium für Wirtschaft und Energie , München, 2020.

[90] "Liquid hydrogen market - growth, trends, Covid-19 impact, and forecasts," Mordor Intelligence, [Online]. Available: https://www.mordorintelligence.com/industry-reports/liquid-hydrogen-market.

[91] D. Graeber, "Exxon planning largest hydrogen production facility in the world," United Press International, Inc., 30 01 2023. [Online]. Available: https://www.upi.com/Top_News/US/2023/01/30/exxon-blue-hydrogen-baytown/6701675093684/. [Accessed 03 02 2023].

[92] T. Gößmann, "H2-Startnetz 2030 (aus dem NEP Gas 2020-2030)," FNB Gas, [Online]. Available: https://fnb-gas.de/wasserstoffnetz/h2-startnetz-2030/. [Accessed 15 11 2021].

[93] "ChemicalParks Make it in Germany," German Chemical Industry Association (VCI), [Online]. Available: https://chemicalparks.com/. [Accessed 08 03 2021].

[94] K. Ganz, T. H. T. Kern and S. Pichlmaier, "Studie zur Regionalisierung von PtG-Leistungen für den Szenariorahmen NEP Gas 2020 – 2030," Forschungsgesellschaft für Energiewitschaft mbH, München, 2019.

[95] IRENA, "Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5^{o}C Climate Goal," International Renewable Energy Agency, Abu Dhabi, 2020.

[96] "H-TEC PEM-Elektrolyseure HCS," H-TEC Systems, [Online]. Available: https://www.h-tec.com/wasserstoff/?campaignId=228597&g_campaignid=19243796604&g_adgroupid=143060804143&g_creative=641339996309&g_targetid=kwd-

1945258278475&g_keyword=wasserstoff%20elektrolyseure&g_device=c&g_adposition=&gclid=Cj0KCQjw27mhBhC9ARIsAIFsETElg. [Accessed 06 04 2023].

[97] J. Incer-Valverde, J. Mörsdorf, T. Morosuk and G. Tsatsaronis, "Power-to-liquid hydrogen: Exergy-based evaluation of a large-scale system," *International Journal of Hydrogen Energy,* vol. 48, no. 31, pp. 11612-11627, 2023.

[98] Siemens, "Siemens Energy and Air Liquide to develop a large scale electrolyzer partnership for sustainable hydrogen production," Siemens Energy, 08 02 2021. [Online]. Available: https://press.siemens-energy.com/global/en/pressrelease/siemens-energy-and-air-liquide-develop-large-scale-electrolyzer-partnership. [Accessed 24 02 2021].

[99] nel ASA, "Nel ASA: Enters into MoU with Iberdrola to develop large scale green hydrogen project and the hydrogen technology value chain in Spain," nel ASA, 18 11 2020. [Online]. Available: https://nelhydrogen.com/press-release/nel-asa-enters-into-mou-with-iberdrola-to-develop-large-scale-green-hydrogen-project-and-the-hydrogen-technology-value-chain-in-spain/. [Accessed 24 02 2021].

[100] Fuel Cell Works, "Rotterdam boost hydrogen economy with new infrastructure," Fuel Cell Works, 10 05 2020. [Online]. Available: https://fuelcellsworks.com/news/rotterdam-boosts-hydrogen-economy-with-new-infrastructure/. [Accessed 24 02 2021].

[101] Vattenfall, "Mitsubishi Heavy Industries, Shell, Vattenfall and Wärme Hamburg sign Letter of Intent for 100 MW hydrogen project at Moorburg in Hamburg," Vattenfall, 22 01 2021. [Online]. Available: https://group.vattenfall.com/press-and-media/pressreleases/2021/mitsubishi-heavy-industries-shell-vattenfall-and-warme-hamburg-sign-letter-of-intent-for-100-mw-hydrogen-project-at-moorburg-in-hamburg. [Accessed 24 02 2021].

[102] Vattenfall, "Vattenfall and Preem look into large-scale production of fossil-free hydrogen," Vattenfall, 21 02 2021. [Online]. Available: https://group.vattenfall.com/press-and-media/pressreleases/2021/vattenfall-and-preem-look-into-large-scale-production-of-fossil-free-hydrogen-in-lysekil. [Accessed 24 02 2021].

[103] Thyssenkrupp, "First green hydrogen project becomes reality: thyssenkrupp to install 88 megawatt water electrolysis plant for Hydro-Québec in Canada," Thyssenkrupp , 18 01 2021. [Online]. Available: https://www.thyssenkrupp.com/en/newsroom/press-releases/pressdetailpage/first-green-hydrogen-project-becomes-reality--thyssenkrupp-to-install-88-megawatt-water-electrolysis-plant-for-hydro-quebec-in-canada-93778. [Accessed 24 02 2021].

[104] Linde, "Linde to Build, Own and Operate World's Largest PEM Electrolyzer for Green Hydrogen," Linde, 13 01 2021. [Online]. Available: https://www.linde.com/news-media/press-releases/2021/linde-to-build-own-and-operate-world-s-largest-pem-electrolyzer-for-green-hydrogen. [Accessed 24 02 2021].

[105] F. Calise, M. D'Accadia, M. Santarelli, A. Lanzini and D. Ferrero, "Electrochemical hydrogen generation," in *Solar hydrogen production: Processes, Systems and Technologies*, Naples, Italy, Academic Press, 2019, p. 299315.

[106] R. Pinsjy, P. Sabharwall, J. Hartvigsen and J. O´Brien, "Comparative review of hydrogen production technologies for nuclear hybrid energy systems," *Progress in Nuclear Energy,* vol. 123, p. 103317, 2020.

[107] S. Shiva Kumar and V. Himabindu, "Hydrogen production by PEM water electrolysis – A review," *Materials Science for Energy Technologies,* vol. 2, pp. 442-454, 2019.

[108] M. Ni, M. Leung and D. Leung, "Energy and exergy analysis of hydrogen production by a proton exchange membrane PEM electrolyser plant," *Energy Conversion and Management,* vol. 49, pp. 2748-2756, 2008.

[109] A. Kazim, "Exergetic efficiency of a PEM electrolyser at various operating temperatures and pressures," *Int. J. Exergy,* vol. 1, no. 1, pp. 47-59, 2004.

[110] E. Nanaki and C. Koroneos, "Exergetic Aspects of Hydrogen Energy Systems - The Case Study of a Fuel Cell Bus," *Sustainability,* vol. 9, p. 276, 2017.

[111] I. Ertesvag, "Sensitivity of chemical exergy for atmospheric gases and gaseous fuels to variations in ambient conditions," *Energy Conversion and Management,* vol. 47, no. 7, pp. 1983-1995, 2007.

[112] P. Ahmadi, I. Dincer and M. Rosen, "Energy and exergy analyses of hydrogen production via solar-boosted ocean thermal energy conversion and PEM electrolysis," *International Journal of Hydrogen Energy,* vol. 38, pp. 1795-1805, 2013.

[113] L. Bertuccioli, A. Chan, D. Hart, F. Lehner, B. Madden and E. Standen, "Development of Water Electrolysis in the European Union," Fuel Cells and Hydrogen Joint Undertaking, Lausanne, 2014.

[114] Hydrogen Council, "Hydrogen Insights A perspective on hydrogen investment, market development and cost competitiveness," McKinsey & Company, 2021.

[115] S. Saba, M. Müller, M. Robinius and D. Stolten, "The investment costs of electrolysis – A comparison of cost studies from the past 30 years," *International Journal of Hydrogen Energy,* vol. 43, no. 3, pp. 1209-1223, 2018.

[116] IEA, "ETP Clean Energy Technology Guide," International Energy Agency, Paris, 2020.

[117] M. David, C. Ocampo-Martínez and R. Sánchez-Peña, "Advances in Alkaline water electrolyser: A review," *Journal of Energy Storage,* vol. 23, pp. 392-403, 2019.

[118] K. Zouhri and S.-y. Lee, "Evaluation and optimization of the alkaline water electrolysers ohmic polarization: exergy study," *International Journal of Hydrogen,* vol. 41, pp. 7253-7263, 2016.

[119] A. Jalalzadeh-Azar, "Potential role of exergy in analysis of hydrogen infrastructure," Sacramento, California, 2008.

[120] Hydrogen Council, "Path to hydrogen competitiveness: A cost perspective," Hydrogen Council, EU, 2020.

[121] IEA, "Hydrogen," International Energy Agency, Paris, 2022.

[122] "European Hydrogen Backbone," 2022.

[123] "Natural gas supply in Germany," Federal Ministry of Economic Affairs and Energy, 2021. [Online]. Available: https://www.bmwi.de/Redaktion/EN/Artikel/Energy/gas-natural-gas-supply-in-germany.html. [Accessed 12 11 2021].

[124] A. Tidey, "Hydrogen pipeline between Spain and France to be complete by 2030 and cost €2.5 billion," euronews, 09 12 2023. [Online]. Available: https://www.euronews.com/my-europe/2022/12/09/hydrogen-pipeline-between-spain-and-france-to-be-complete-by-2030-and-cost-25-billion. [Accessed 03 02 2023].

[125] GetH2, "Starting point and expansion of the infrastructure for green hydrogen," 2023. [Online]. Available: https://www.get-h2.de/en/implementation/. [Accessed 03 02 2023].

[126] J. Hodges, W. Geary, S. Graham, P. Hooker and R. Goff, "Injecting hydrogen into the gas network - a literature search," Health and Safety Laboratory, 2015.

[127] C. Quarton and S. Samsatli, "Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling?," *Renewable and Sustainable Energy Reviews,* vol. 98, pp. 302-316, 2018.

[128] European Turbine Network, "Hydrogen Gas Turbine," 2020.

[129] NS Energy, "Nuon Magnum Power Plant," 21 04 2021. [Online]. Available: https://www.nsenergybusiness.com/projects/nuon-magnum-power-plant/#.

[130] E. Frank, A. Elgowainy, K. Reddi and A. Bafana, "Life-cycle analysis of greenhouse gas emissions from hydrogen delivery: A cost-guided analysis," *International Journal of Hydrogen Energy,* vol. 46, pp. 22670-22683, 2021.

[131] K. Stolzenburg and R. Mubbala, "Integrated Design for Demonstration of Efficient Liquefaction of Hydrogen (IDEALHY)," Fuel Cells and Hydrogen Joint Undertaking (FCH JU) , 2013.

[132] H. Dagdougui, R. Sacile, C. Bersani and A. Ouammi, "Chapter 2 - Hydrogen Production and Current Technologies," in *Hydrogen Infrastructure for Energy Applications*, Academic Press, 2018, pp. 7-21.

[133] M. Kayfeci, A. Keçebaş and M. Bayat, "Chapter 3 - Hydrogen production, Editor(s): Francesco Calise, Massimo Dentice D'Accadia, Massimo Santarelli, Andrea Lanzini, Domenico Ferrero," in *Solar Hydrogen Production*, Academia Press, 2019, pp. 45-83.

[134] "Ammonia to Green Hydrogen Project: Feasibility Study," Ecuity, STFC, Engie, Siemens, Birmingham, 2020.

[135] S. Marsh and M. Chambers, "Germany freezes Nord Stream 2 gas project as Ukraine crisis deepens," Reuters, 22 02 2022. [Online]. Available: https://www.reuters.com/business/energy/germanys-scholz-halts-nord-stream-2-certification-2022-02-22/. [Accessed 11 03 2022].

[136] "Facts and Myths," Nord Stream 2 , 2021. [Online]. Available: https://www.nord-stream2.com/media-info/facts-myths/. [Accessed 12 11 2021].

[137] G. Brändle, M. Schönfisch and S. Schulte, "Estimating long-term global supply costs for low-carbon hydrogen," *Applied Energy,* vol. 302, p. 117481, 2021.

[138] J. Bard, N. Gerhardt, P. Selzam, M. Beil, M. Wiemer and M. Buddensiek, "The limitations of hydrogen blending in the european gas grid," Fraunhofer IEE, Berlin, 2022.

[139] J. Dewar, "Liquid Hydrogen," *Science,* vol. 8, no. 183, pp. 3-6, 1898.

[140] K. D. Timmerhaus and T. M. Flynn, Cryogenic Process Engineering, Boston: Springer US, 1989.

[141] N. Sönnichsen, "Consumption of liquid hydrogen in the United States in 2018 and 2024," Statista, 19 10 2021. [Online]. Available: https://www.statista.com/statistics/1113095/us-liquid-hydrogen-consumption/. [Accessed 01 02 2023].

[142] M. Vos, J. Douma and A. Van den Noort, "Study on the Import of Liquid Renewable Energy: Technology Cost Assessment," Det Norske Veritas, 10 2020. [Online]. Available: https://www.gie.eu/wp-content/uploads/filr/2598/DNV-GL_Study-GLE-Technologies-and-costs-analysis-on-imports-of-liquid-renewable-energy.pdf. [Accessed 03 12 2021].

[143] "Liquid Hydrogen Market By Production Method (Steam Methane Reforming (SMR), Electrolysis of Water, Coal Gasification, Others), By Distribution Channel, And By End Use Industry, Forecasts To 2027," Reports and Data, 04 2020. [Online]. Available: https://www.reportsanddata.com/report-detail/liquid-hydrogen-market. [Accessed 01 02 2023].

[144] IRENA, "Green hydrogen supply: A guide to policy making," International Renewable Energy Agency, Abu Dhabi., 2021.

[145] U. Cardella, L. Decker and H. Klein, "Economically viable large-scale hydrogen liquefaction," in *IOP Conf. Ser. Mater. Sci. Eng*, 2017.

[146] Linde, "Latest Global Trend in Liquid Hydrogen Production," HYPER , Norway, 2019.

[147] G. Petitpas, "Boil-off losses along LH2 pathway," Lawrence Livermore National Laboratory, U.S., 2018.

[148] C. Baker and R. Shaner, "A Study of the Efficiency of Hydrogen Liquefaction," *International Journal of Hydrogen Energy ,* vol. 3, no. 3, p. 321–334, 1978.

[149] Y. E. Yuksel, M. Ozturk and I. Dincer, "Analysis and assessment of a novel hydrogen liquefaction process," *International Journal of Hydrogen Energy,* pp. 1-10, 2017.

[150] K. Ohlig and L. Decker, "The Latest Developments and Outlook for Hydrogen liquefaction technology," in *AIP Conference Proceedings Linde Kryotechnik AG*, Pfungen, Switzerland, 2013.

[151] P. Donaubauer, U. Cardella, L. Decker and H. Klein, "Kinetics and Heat Exchanger Design for Catalytic Ortho-Para Hydrogen Conversion during Liquefaction," *Chemical & Engineering Technology,* vol. 42, no. 3, p. 669–679, 2019.

[152] D. Berstad, J. Stang and P. Neksa, "Comparison criteria for large-scale hydrogen liquefaction processes," *Int. J. Hydrog. Energy,* vol. 34, no. 3, p. 1560–1568, 2009.

[153] A. Okunlola, T. Giwa, G. D. Lullo, M. Davis, E. Gemechu and A. Kumar, "Techno-economic assessment of low-carbon hydrogen export from Western Canada to Eastern Canada, the USA, the Asia-Pacific, and Europe," *International Journal of Hydrogen Energy,* vol. 47, pp. 6453-6477, 2022.

[154] R. Singh, "Japan's Suiso Frontier loading liquid hydrogen at Hastings, likely departure within days," S&P Global, 25 01 2022. [Online]. Available: https://www.spglobal.com/platts/en/market-insights/latest-news/energy-transition/012522-japans-suiso-frontier-loading-liquid-hydrogen-at-hastings-likely-departure-within-days. [Accessed 14 02 2022].

[155] "Hyosung to construct world’s largest liquid hydrogen plant in South Korea," 04 29 2020. [Online]. Available:

https://www.worldconstructionnetwork.com/news/hyosung-to-construct-world-s-largest-liquid-hydrogen-plant-in-south-korea/. [Accessed 22 02 2021].

[156] M. Bailey, "Plug Power to deliver two hydrogen liquefaction systems to TC Energy," Chemical Engineering, 10 01 2023. [Online]. Available: https://www.chemengonline.com/plug-to-deliver-two-hydrogen-liquefaction-systems-to-tc-energy/?oly_enc_id=8797H8308467A5S. [Accessed 03 02 2023].

[157] J. Essler, C. Haberstroh, H. Quack, H. T. Walnum, D. Berstad, P. Neska, J. Stang, M. Börsch, F. Holdner , L. Decker and P. Treite, "Report on technology overview and barriers to energy- and cost-efficient large-scale hydrogen liquefaction," 2012.

[158] S. Krasae-in, J. Stang and P. Neksa, "Development of large-scale hydrogen liquefaction processes from 1898 to 2009," *International Journal of Hydrogen Energy,* vol. 35, pp. 4524-4533, 2010.

[159] H. Quack, "Conceptual Design of a High Efficiency Large Capacity Hydrogen Liquefier," in *AIP Conference Proceedings*, Wisconsin, 2002.

[160] D. Berstad, J. Stang and P. Nekså, "Large-scale hydrogen liquefier utilising mixed-refrigerant pre-cooling," *Int. J. Hydrog. Energy,* vol. 35, no. 10, p. 4512–4523, 2010.

[161] G. Valenti, "Hydrogen liquefaction and liquid hydrogen storage," in *Compendium of Hydrogen Energy*, Milan, Elsevier, 2016, pp. 27-51.

[162] W. Staats, J. Smith and J. Brisson, "Analysis of a Supercritical Hydrogen Liquefaction Cycle," *Cryocoolers 16 Massachusetts Institute of Technology,* p. 721–730, 2008.

[163] M. Aasadnia and M. Mehrpooya, "Conceptual design and analysis of a novel process for hydrogen liquefaction assisted by absorption precooling system," *Journal of Cleaner Production,* vol. 205, p. 565–588, 2018.

[164] U. Cardella, "Large-scale hydrogen liquefaction under the aspect of economic viability," Dissertation, TU München, München, 2018.

[165] L. Yin and Y. Ju, "Process optimization and analysis of a novel hydrogen liquefaction cycle," *Int. J. Refrig,* vol. 110, p. 219–230, 2020.

[166] "Hydrogen Storage," Hydrogen and Fuel Cell Technologies Office U.S., [Online]. Available: https://www.energy.gov/eere/fuelcells/hydrogen-storage#:~:text=Hydrogen%20can%20be%20stored%20physically,pressure%20is%20%E2%88%92252.8%C2%B0C.. [Accessed 01 02 2023].

[167] Macchi and Valenti, "„Proposal of an innovative, high-efficiency, large-scale hydrogen liquefier," *Int. J. Hydrog. Energy,* vol. 33, no. 12, p. 3116–3121, 2008.

[168] S. Krasae-in, J. H. Stang and P. Neska, "Simulation on a proposed large-scale liquid hydrogen plant using a multi-component refrigerant refrigeration system," *International Journal of Hydrogen Energy,* vol. 35, pp. 12531-12544, 2010.

[169] M. Asadnia and M. Mehrpooya, "A novel hydrogen liquefaction process configuration with combined mixed refrigerant systems," *Int. J. Hydrog. Energy,* vol. 42, no. 23, p. 15564–15585, 2017.

[170] C. Yilmaz, "A Case Study: Exergoeconomic Analysis and Genetic Algorithm Optimization of Performance of a Hydrogen Liquefaction Cycle Assisted by Geothermal Absorption Precooling Cycle," *Renewable Energy ,* vol. 128, pp. 68-80, 2017.

[171] H. Zhang, L. Wang, J. Van Herle, F. Maréchal and U. Desideri, "Techno-economic comparison of green ammonia production processes," vol. 259, 2020.

[172] L. Fernández, "Ammonia production worldwide from 2010 to 2021," Statista, 31 05 2022. [Online]. Available: https://www.statista.com/statistics/1266378/global-ammonia-production/. [Accessed 01 02 2023].

[173] A. Valera-Medina, H. Xiao, M. Owen-Jones, W. David and P. Bowen, "Ammonia for power," *Progress in Energy and Combustion Science,* vol. 69, pp. 63-102, 2018.

[174] "Ammonia As Hydrogen Carrier to Unlock the Full Potential of Green Renewables," Ammonia Energy Conference, 13 11 2019. [Online]. Available: https://www.ammoniaenergy.org/paper/ammonia-as-hydrogen-carrier-to-unlock-the-full-potential-of-green-renewables/#:~:text=Ammonia%20presents%20a%20high%20hydrogen,%C2%B0C%20and%208.6%20bars.. [Accessed 05 02 2021].

[175] R. Lan and S. Tao, *Direct ammonia alkaline anion-exchange membrane fuel cells.,* Electrochem. Solid State Lett., 2010.

[176] X. Xu, E. Liu, N. Zhu, F. Liu and F. Qian, "Review of the Current Status of Ammonia-Blended Hydrogen Fuel Engine Development," *Energies,* vol. 15, p. 1023, 2022.

[177] IEA, "World Energy Outlook 2021," International Energy Agency, Paris, 2021.

[178] Siemens AG, "'Green' ammonia is the key to meeting the twin challenges of the 21st century," Siemens Energy, 2021. [Online]. Available: https://www.siemens-energy.com/uk/en/offerings-uk/green-ammonia.html. [Accessed 15 10 2021].

[179] W. Avery, *A role for ammonia in the hydrogen economy,* Vols. 13, 761–773, Int. J. Hydrog. Energy , 1988.

[180] M. Fecke, S. Garner and B. R. Cox, *Review of global regulations for anhydrous ammonia production, use, and storage,* 2016.

[181] T. Brown, "Industry report sees multi-billion ton market for green ammonia," Ammonia Energy Association, 04 06 2020. [Online]. Available: https://www.ammoniaenergy.org/articles/industry-report-sees-multi-billion-ton-market-for-green-ammonia/#:~:text=Argus%20estimates%20that%20the%20production,market%20price%20of%20conventional%20ammonia.. [Accessed 15 10 2021].

[182] B. Shiozawa, "The Cost of CO2-free Ammonia," Ammonia Energy Association , 12 11 2020. [Online]. Available: https://www.ammoniaenergy.org/articles/the-cost-of-co2-free-ammonia/. [Accessed 26 10 2021].

[183] D. Sheldon, "Methanol Production – A Technical History," *Johnson Matthey Technol. Rev.,* vol. 61, no. 3, pp. 172-182, 2017.

[184] IRENA, "Innovation Outlook : Renewable Methanol, International Renewable Energy Agency," Abu Dhabi, 2021.

[185] D. Marlin, E. Sarron and Ó. Sigurbjörnsson, "Process Advantages of Direct CO2 to Methanol Synthesis," *Front. Chem.,* vol. 6, 2018.

[186] "Methanol Insitute-Overview of Global Methanol," Gregory Dolan, CEO – Methanol Institute, 24 01 2019. [Online]. Available: https://www.methanol.org/wp-content/uploads/2019/01/Dolan-TT-Methanol-Fuel-Blending-Workshop-24-Jan-2018.pdf. [Accessed 25 10 2021].

[187] "Production capacity of methanol worldwide from 2018 to 2020, with a forecast for 2030," Statista, [Online]. Available: https://www.statista.com/statistics/1065891/global-methanol-production-capacity/#:~:text=The%20global%20production%20capacity%20of,million%20metric%20tons%20by%202030.. [Accessed 14 02 2022].

[188] A. Sonthalia, N. Kumar, M. Nomar, V. Geo, S. Thiyagarajan and A. Pugazhendhi, "Moving ahead from hydrogen to methanol economy: scope and challenges," *Clean Technologies and Environmental Policy,* 2021.

[189] K. Atsonis, K. Panopoulos and E. Kakaras, "Investigation of technical and economic aspects for methanol production through CO2 hydrogenation," 2015.

[190] C. Machado, J. Medeiros, O. Araujo and R. Brito Alves, "A comparative analysis of methanol production routes: synthesis gas versus CO2 hydrogenation," 2014.

[191] R. Peters, "Green methanol - Successful calculation of costs," Closed carbon Cycle Mobility, [Online]. Available: http://www.c3-mobility.de/news/green-methanol-succesful-calculation-of-costs/. [Accessed 30 10 2021].

[192] K. Howard, "World's first liquefied hydrogen ship completes voyage in Japan," Pinsent Masons, 12 05 2022. [Online]. Available:

https://www.pinsentmasons.com/out-law/news/worlds-first-liquefied-hydrogen-ship-completes-voyage-in-japan. [Accessed 27 01 2023].

[193] S&P Global , "Dutch Port of Rotterdam targets end-2026 for 'blue' hydrogen plant," S&P Global , 04 05 2021. [Online]. Available: https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/050421-dutch-port-of-rotterdam-targets-end-2026-for-blue-hydrogen-plant. [Accessed 21 07 2021].

[194] "Extending the Reach of the Hydrogen Value Chain With Cutting-edge Liquefaction, Distribution and Storage Technologies," Linde, 2021. [Online]. Available: https://www.linde-engineering.com/en/images/LE_LH2_Technologies_Brochure_RZ_VIEW_51906_tcm19-646805.pdf. [Accessed 02 05 2022].

[195] K. Oshima, Y. Ishizaki, S. Kamiyama, M. Akiyama and M. Okuda, "Utilization of Lh2 and Lng Cold for Generation of Electric Power By a Cryogenic-Type Stirling Engine," *CRYOGENICS,* pp. 310-317, 1978.

[196] S. Furuhama, T. Nakajima and T. Honda, "Rankine cycle engines for utilization of LH2 car fuel as a low-temperature source," *International Journal of Hydrogen Energy,* vol. 18, no. 2, pp. 149-155, 1993.

[197] A. Agazzani, A. Massardo and T. Korakianitis, "An Assessment of the Performance of Closed Cycles With and Without Heat Rejection at Cryonenic Temperatures," *International Gas Turbine and Aeroengine Congress and Exhibition, ASME,* vol. 121, pp. 458-465, July 1996.

[198] G. Bisio, A. Massardo and A. Agazzani, "Combined Helium and Combustion Gas Turbine Plant Exploiting Liquid Hydrogen (LH2) Physical Exergy," *Journal of Engineering for Gas Turbines and Power, ASME,* vol. 118, pp. 257-264, 1996.

[199] H. V. Woolley, R. N. Scott and F. G. Brickwedde, "Compilation of Thermal Properties of Hydrogen in its Various Isotopic and Ortho-Para Modifications," *J. Res. Nat. Bureau Standards,* vol. 41, pp. 379-475, 1948.

[200] A. Fyke, D. Li, P. Crane and D. Scott, "Recovery of thermomechanical exergy from cryofuels," *International Journal of Hydrogen Energy,* vol. 22, pp. 435-440, 1996.

[201] L. Trevisani, M. Fabbri, F. Negrini and P. L. Ribani, "Advanced energy recovery systems from liquid hydrogen," *Energy Conversion and Management,* vol. 48, p. 146–154, 2007.

[202] "Thermophysical properties of fluid systems, standard reference database no. 69," NIST, 2022. [Online]. Available: http://webbook.nist.gov/chemistry/fluid/. [Accessed 02 05 2022].

[203] N. Zhang and N. Lior, "A novel Brayton cycle with the integration of liquid hydrogen cryogenic exergy utilization," *International Journal of Hydrogen Energy,* vol. 33, p. 214–224, 2008.

[204] A. Laouir, "Performance analysis of open-loop cycles for LH2 regasification," *International Journal of Hydrogen Energy,* vol. 44, p. 22425–22436, 2019.

[205] J. Incer-Valverde, C. Lugo-Mayor, G. Tsatsaronis and T. Morosuk, "Evaluation of the large-scale hydrogen supply chain and perspectives on LH2 regasification cogeneration systems," *Gas Science and Engineering,* vol. 115, p. 205005, 2023.

[206] H. Griepentrog and P. Sackarendt, "Vaporization of LNG with Closed-Cycle Gas Turbines," in *Proceedings of the Gas Turbine and Fluid Engineering Conference*, New Orleans, USA, 1976.

[207] R. WC, Thermodynamic properties in SI. Department of Mechanical Engineering, Stanford University, 1979.

[208] R. Hancke, T. Holm and Ø. Ulleberg, "The case for high-pressure PEM water electrolysis," *Energy Conversion and Management,* vol. 261, no. 1, p. 115642, 2022.

[209] E. Drexler, R. Amaro, A. Slifka, P. Bradley and D. Lauria, "Operating Hydrogen Gas Transmission Pipelines at Pressures Above 21 MPa," *Pressure Vessel Technology,* vol. 140, no. 6, p. 061702, 2018.

[210] M. Penev, J. Zuboy and C. Hunter, "Economic analysis of a high-pressure urban pipeline concept (HyLine) for delivering hydrogen to retail fueling stations," *Transportation Research Part D: Transport and Environment,* vol. 77, pp. 92-105 , 2019.

[211] General Electric Company, "LMS100 aeroderivative gas turbine," GE Gas Power, 2021. [Online]. Available: https://www.ge.com/gas-power/products/gas-turbines/lms100. [Accessed 27 07 2021].

[212] General Electric Company, "Alternative fuel gas turbine retrofits," GE Power Gas, 2021. [Online]. Available: https://www.ge.com/gas-power/services/gas-turbines/upgrades/alternative-fuel-retrofit. [Accessed 27 07 2021].

[213] T. Morosuk and G. Tsatsaronis, "LNG – Based Cogeneration Systems: Evaluation Using Exergy-Based Analyses," in *InTech*, InTech Open, 2012, pp. 236-266.

[214] A. Klerke, C. H. Christensen, N. Jens and T. Vegge, "Ammonia for hydrogen storage: challenges and opportunities," *Journal of Materials Chemistry,* vol. 18, no. 20, pp. 2304-2310, 2008.

[215] G. Thomas and G. Parks, "Potential Roles of Ammonia in a Hydrogen Economy," U.S. Department of Energy , 2006.

[216] G. Graaf and J. Winkelman, "Chemical equilibria in methanol synthesis including the water–gas shift reaction: a critical reassessment," *Ind. Eng. Chem. Res.,* vol. 55, no. 20, p. 5854–5864, 2016.

[217] F. Schorn, J. L. Breuer, R. Can Samsun, T. Schnorbus, B. Heuser, R. Peters and D. Stolten, "Methanol as a renewable energy carrier: An assessment of production and transportation costs for selected global locations," *Advances in Applied Energy,* vol. 3, no. 100050, 2021.

[218] Y. Shen, Y. Zhan, F. Ning, Y. Du, Y. Huang, T. He and X. Zhou, "Hydrogen generation from methanol at near-room temperature†," *Chem Sci,* vol. 8, no. 11, pp. 7498-7504, 2017.

[219] G. Tsatsaronis, "Combination of Exergetic and Economic Analysis in Energy-Conversion Processes," in *Energy Economics and Management in Industry, Proceedings of the European Congress, Algarve, Portugal, Pergamon Press*, Oxford, England, April 2-5, 1984.

[220] G. Tsatsaronis and T. Morosuk, "Understanding and improving energy conversion systems with the aid of exergy-based methods," *International Journal of Exergy,* vol. 11, no. 4, pp. 518-452, 2012.

[221] T. Morosuk and G. Tsatsaronis, "Splitting physical exergy: theory and application," *Energy,* vol. 167, pp. 698-707, 2019.

[222] J. Szargut, D. Morris and F. Steward, Exergy Analysis of Thermal, Chemical, and Metallurgical Processes, New York: Chemical, and Metallurgical Processes, 1988, pp. New York: Hemisphere, New York,.

[223] M. Holst, S. Aschbrenner, T. Smolinka, C. Voglstätter and G. Grimm, "Cost forecast for low temperature electrolysis – technology driven bottom-up prognosis for PEM and alkaline water electrolysis systems," Fraunhofer ISE, Freiburg, 2021.

[224] D. O. Berstad, J. H. Stang and P. Neska, "Comparison criteria for large-scale hydrogen liquefaction processes," *International Journal of Hydrogen Energy,* no. 34, pp. 1560-1568, 2009.

[225] J. W. Leachman, R. T. Jacobsen, S. G. Penoncello and E. W. Lemmon, "Fundamental Equations of State for Parahydrogen, Normal Hydrogen, and Orthohydrogen," *J. Phys. Chem,* vol. 38, p. 72, 2009.

[226] A. Bejan, G. Tsatsaronis and M. Moran, Thermal Design and Optimization,, New York, United States: Wiley, 1996.

[227] G. Tsatsaronis and F. Cziesla, "Thermoeconomics," *Encyclopedia of Physical Science and Technology,* vol. 16, no. Third Edition, pp. 659-680, Academic Press, 2002.

[228] G. D. Ulrich and P. T. Vasudeva, *Chemical Engineering ProcessDesign and Economics: A Practical Guide,* Durham: Process Pub, 2004.

[229] M. S. Peters, K. D. Timmerhaus and R. E. West, .Plant Design and Economics forChemical Engineers, New York: McGraw-Hil, 2003.

[230] H. Ansarinasab, M. Mehrpooya and A. Mohammadi, "Advanced Exergy and Exergoeconomic Analyses of a Hydrogen Liquefaction Plant Equipped with Mixed Refrigerant System," *Journal of Cleaner Production,* no. 144, pp. 248-259, 2017.

[231] R. Smith, Chemical Process Design and Integration, Chichester, West Sussex: John Wiley & Sons, 2016.

[232] S. Tesch, *Exergy-Based Methods Applied to the Processes of LNG Regasification Integrated into Air Separation Unit,* Berlin: Dissertation TU Berlin, 2019.

[233] C. Maxwell, "Cost Indices," Towering skills, 26 01 2023. [Online]. Available: https://www.toweringskills.com/financial-analysis/cost-indices/. [Accessed 24 02 2020].

[234] K. Guthrie, Process plant estimating, evaluation, and control, Craftsman: California, 1974.

[235] "DOE Hydrogen and Fuel Cells Program Record," Department of Energy USA, 14 09 2020. [Online]. Available: https://www.hydrogen.energy.gov/pdfs/20004-cost-electrolytic-hydrogen-production.pdf. [Accessed 04 06 2023].

[236] P. Hannam, "Australian researchers claim ‘giant leap’ in technology to produce affordable renewable hydrogen," The Guardian, 16 05 2022. [Online]. Available: https://www.theguardian.com/australia-news/2022/mar/16/australian-researchers-claim-giant-leap-in-technology-to-produce-affordable-renewable-hydrogen. [Accessed 06 04 2023].

[237] "Germany Electricity Price," Trading Economics, 17 04 2023. [Online]. Available: https://tradingeconomics.com/germany/electricity-price. [Accessed 17 04 2023].

[238] "Safe Practices Guide for Cryogenic Air Separation Plants," Asia Industrial Gases Association, 2008. [Online]. Available: http://asiaiga.org. [Accessed 17 03 2023].

[239] K. Verfondern, "Safety Considerations on Liquid Hydrogen," Forschungszentrum Julich GmbH, 2008.

[240] S. Tesch, Exergy-Based Methods Applied to the Processes of LNG Regasification Integrated into Air Separation Units, Berlin: TU Berlin, 2019.

[241] J. Couper, W. Penney and J. Fair, "Chemical Process Equipment revised 2E: Selection and Design," Gulf Professional Publishing, 2009.

[242] "Corporate Taxation in Germany," Germany Trade & Investment, 2023. [Online]. Available: https://www.gtai.de/en/invest/investment-guide/corporate-taxation. [Accessed 15 02 2023].

[243] Gas Turbine World: Gas Turbine World Handbook, Pequot Publishing, 2003 .

[244] M. Brunelli, Introduction to the Analytic Hierarchy Process, Aalto: Springer, 2014.

[245] T. Saaty, The Analytic Hierarchy Process: Planning, Priority Setting, Resource Allocation, McGraw-Hill International Book Company, 1980.

[246] H. Shih and D. Olson, TOPSIS and Its Extensions: A Distance-Based MCDM Approach, Cham: Springer International Publishing, 2022.

[247] E. Zavadskas, Z. Turskis, J. Antucheviciene and A. Zakarevicius, "Optimization of Weighted Aggregated Sum Product Assessment," *Elektronika ir Elektrotechnika,* vol. 122, no. 6, 2012.

[248] B. Radowitz and R. Parkes, "EU to offer 'fixed premium' to green hydrogen producers in attempt to compete with US H2 tax credits," Hydrogen Insight, 01 02 2023. [Online]. Available: https://www.hydrogeninsight.com/production/eu-to-offer-fixed-premium-to-green-hydrogen-producers-in-attempt-to-compete-with-us-h2-tax-credits/2-1-1397068. [Accessed 15 02 2023].

[249] C. Clifford, "The clean hydrogen energy economy was a dream. The climate bill could make it a reality this decade," CNBC, 08 09 2022. [Online]. Available: https://www.cnbc.com/2022/09/08/clean-hydrogen-industry-got-huge-boost-from-inflation-reduction-act.html. [Accessed 13 02 2023].

[250] UNECE, "Technology Brief Hydrogen," United Nations Economic Commission for Europe Task Force on Hydrogen, Geneva, 2021.

[251] WEC, "Working Paper: Regional insights into low-carbon hydrogen scale up | World Energy Insights," World Energy Council, 2022, 2022.

[252] IEA, "CCUS in Clean Energy Transitions," International Energy Agency, Paris, 2020.

[253] IEA, "Hydrogen Supply," International Energy Agency, Paris, 2022.

[254] "Hydrogen Production: Thermochemical Water Splitting," Hydrogen and Fuel Cell Technologies Office US, [Online]. Available: https://www.energy.gov/eere/fuelcells/hydrogen-production-thermochemical-water-splitting. [Accessed 03 05 2023].

[255] A. Ajanovic, M. Sayer and R. Haas, "The economics and the environmental benignity of different colors of hydrogen," *International Journal of Hydrogen Energy,* vol. 47, no. 57, pp. 24136-24154, 2022.

[256] J. Incer-Valverde, J. Mörsdorf, T. Morosuk and G. Tsatsaronis, "Power-to-liquid hydrogen: Exergy-based evaluation of a large-scale system," *International Journal of Hydrogen Energy,* vol. 48, no. 31, pp. 11612-11627, 2023.

[257] M. Binder, M. Kraussler, M. Kuba and M. Luisser, "Hydrogen from biomass gasification," IEA Bioenergy, 2018.

[258] N. Amponsah, M. Troldborg, B. Kington, I. Aalders and R. L. Hough, "Greenhouse gas emissions from renewable energy sources: A review of lifecycle considerations," *Renewable and Sustainable Energy Reviews,* vol. 39, pp. 461-475, 2014.

[259] P. Woods, H. Bustamante and K. Aguey-Zinsou, "The hydrogen economy - Where is the water?," *Energy Nexus,* vol. 7, p. 100123, 2022.

[260] A. Acar and I. Dincer, "Comparative assessment of hydrogen production methods from renewable and non-renewable sources," *International Journal of Hydrogen Energy,* vol. 39, no. 1, p. 1–12, 2014.

[261] H. Song, G. Yang, P. Xue, Y. Li, J. Zou, S. Wang, H. Yang and H. Chen, "Recent development of biomass gasification for H2 rich gas production," *Applications in Energy and Combustion Science,* vol. 10, p. 100059, 2022.

[262] T. Lepage, M. S. Q. Kammoun and A. Richel, "Biomass-to-hydrogen: A review of main routes production, processes evaluation and techno-economical assessment," *Biomass and Bioenergy,* vol. 144, p. 105920, 2021.

[263] A. Mehmeti, A. Angelis-Dimakis, G. Arampatzis, S. McPhail and S. Ulgiati, "Life Cycle Assessment and Water Footprint of Hydrogen Production Methods: From Conventional to Emerging Technologies," *Environments,* vol. 5, no. 24, 2018.

[264] K. Crane, F. Altgelt and M. Micheli, "Water consumption for the production of green hydrogen," Global Alliance Powerfuels Brief and dena, Berlin, 2021.

[265] F. Altgelt, M. Micheli, K. Sailer and K. Crone, "Water Consumption of Powerfuels," Deutsche Energie-Agentur GmbH (dena), Berlin, 2021.

[266] "Ammonia As Hydrogen Carrier to Unlock the Full Potential of Green Renewables," Ammonia Energy Association, 23 11 2019. [Online]. Available: https://www.ammoniaenergy.org/paper/ammonia-as-hydrogen-carrier-to-unlock-the-full-potential-of-green-renewables/. [Accessed 05 03 2021].

[267] M. Aziz, A. Wijatanta and A. Nandiyanto, "Ammonia as Effective Hydrogen Storage: A Review on Production , Storage and Utilization," vol. 13, 2020.

[268] Serban Moldoveanu, "General information about pyrolysis," in *Analytical Pyrolysis of Natural Organic Polymers* , El Sevier, 2021, pp. 3-27.

[269] M. Fasihi, R. Weiss, J. Savolainen and C. Breyer, "Global potential of green ammonia based on hybrid PV-wind power plants," *Applied Energy,* vol. 294, p. 116170, 2021.

[270] N. Salmon and R. Bañares-Alcántara, "Green ammonia as a spatial energy vector: a review," *Sustainable Energy & Fuels,* vol. 5, pp. 2814-2839, 2021.

[271] H. Kobayashi, A. Hayakawa, . Kunkuma and E. Okafor, "Science and technology of ammonia combustion," *Proceedings of the Combustion Insitute. Elsevier,* vol. 37, no. 1, pp. 109-133, 2019.

[272] A. Wijayanta, T. Oda, C. Purnomo, T. Kashiwagi and M. Aziz, "Liquid hydrogen, methylcyclohexane, and ammonia as potential hydrogen storage: Comparison review," vol. 44, 2019.

[273] A. Ince, C. Colpan, A. Hagen and M. Serincan, "Modeling and simulation of Power-to-X systems: A review," *Fuel,* vol. 304, p. 121354, 2021.

[274] N. Kurmayer, "€2 billion 'Clean Hydrogen Partnership' signals move away from hydrogen cars," Euractiv, 02 12 2021. [Online]. Available: https://www.euractiv.com/section/energy/news/e2-billion-clean-hydrogen-partnership-another-move-away-from-hydrogen-cars/. [Accessed 07 12 2021].

[275] M. Webber, "The water intensity of the transitional hydrogen economy," *Environmental Research Letters,* vol. 3, 2007.

[276] P. Kasten and C. Heinemann, "Not to be taken for granted: climate protection and sustainability through PtX," Öko-Institut e.V., Berlin, 2019.

[277] X. Shi, X. Liao and Y. Li, "Quantification of fresh water consumption and scarcity footprints of hydrogen from water electrolysis: A methodology framework," *Renewable Energy,* vol. 154, pp. 786-796, 2020.

[278] Ministerial Council on Renewable Energy Hydrogen, "Basic Hydrogen Strategy," Ministry of Economy, Trade and Industry, Japan, 2017.

[279] "The Hydrogen Deployment Plan for Energy Transition," Minister for the Ecological and Inclusive Transition, Paris, 2018.

[280] "Hydrogen Economy Roadmap of Korea," Government of Korea, 2019.

[281] "A vision for Hydrogen in New Zealand," Ministry of Business, Innovation & Employment, Wellington, 2019.

[282] "Australia´s National Hydrogen Strategy," COAG Energy Council Hydrogen Working Group, Australia, 2019.

[283] "Government Strategy on Hydrogen," Ministry of Economic Affairs and Climate Policy, The Netherlands, 2020.

[284] "Portugal National Hydrogen Strategy," República Portuguesa, 2020.

[285] "The Norwegian Government’s hydrogen strategy," Norwegian Ministry of Petroleum and Energy Strategy and Ministry of Climate and Environment, 2020.

[286] "A hydrogen strategy for a climate-neutral Europe," European Commission, Brussels, 2020.

[287] "National strategy for the development of decarbonised and renewable hydrogen in France," French Government, Paris, 2020.

[288] "Hydrogen Roadmap," Ministry for ecological transition and the demographic challenge, Spain, 2020.

[289] "The Government of the Russian Federation approved an action plan for the development of hydrogen energy," Ministry of Energy of the Russian Federation, 22 10 2020. [Online]. Available: https://minenergo.gov.ru/node/19194. [Accessed 11 10 2021].

[290] J. Laurikko, J. Ihonen, J. Kiviaho, O. Himanen, R. Weiss, V. Saarinen, J. Kärki and M. Hurskainen, "National Hydrogen Roadmap for Finland," Business Finland, Finland, 2020.

[291] "National Green Hydrogen Strategy," Ministry of Energy, Government of Chile, Santiago, 2020.

[292] "Hydrogen Program Plan," U.S. Department of Energy, 2020.

[293] "Hydrogen Strategy for Canada," Government of Canada, 2020.

[294] "Scottish Hydrogen Assessment," Scottish Government, Edinburgh, 2020.

[295] "Hydrogen strategy for fossil free competitiveness," Fossil Free Sweden, Sweden, 2021.

[296] S. Jacob, "National Hydrogen Mission: All you need to know about India's plans and potential," Money Control, 10 02 2021. [Online]. Available: https://www.moneycontrol.com/news/business/economy/national-hydrogen-mission-all-you-need-to-know-about-indias-plans-and-potential-6486731.html. [Accessed 07 10 2021].

[297] "Hungary´s National Hydrogen Strategy," The Hungary Government, 2021.

[298] "Towards the Green Hydrogen Roadmap in Paraguay," Viceministry of Mines and Energy, Paraguay, 2021.

[299] "National Hydrogen Strategy “Prepared for the future”," Ministry of Economy, Slovakia, 2021.

[300] "The Czech Republic´s Hydrogen Strategy," Ministry of Industry and Trade, Prague, 2021.

[301] K. Kwarteng, "UK Hydrogen Strategy," HM Government, London, 2021.

[302] "National Green Hydrogen Strategy," Ministry of Energy Transition and Sustainable Development, Morocco, 2021.

[303] E. Mandel, "Colombia publishes hydrogen roadmap," H2 Bulletin, 02 10 2021. [Online]. Available: https://www.h2bulletin.com/colombia-publishes-hydrogen-roadmap/. [Accessed 07 10 2021].

[304] "The Belgian federal hydrogen vision and strategy," Allen & Overy LLP, 05 11 2021. [Online]. Available: https://www.allenovery.com/en-gb/global/news-and-insights/publications/the-belgian-federal-hydrogen-vision-and-strategy#:~:text=The%20Belgian%20federal%20hydrogen%20strategy,possible%20and%20well%20before%202050.. [Accessed 01 03 2022].

[305] "Hydrogen Society Roadmap for South Africa," Department of Science and Innovation Republic of South Africa, South Africa , 2021.

[306] "Polish Hydrogen Strategy," IEA, 30 04 2021. [Online]. Available: https://www.iea.org/policies/12730-polish-hydrogen-strategy. [Accessed 07 10 2021].

[307] "Hydrogen strategy of the Republic of Croatia until 2050," Ministry of Economy and Sustainable Development, Zagreb, 2022.

[308] Yuki, "China’s National Hydrogen Development Plan," Energy Iceberg, 06 04 2022. [Online]. Available: China’s National Hydrogen Development Plan. [Accessed 26 04 2023].

[309] "Wasserstoffstrategie für Österreich," Federal Ministry Republic of Austria, Wien, 2022.

[310] "Programa Nacional do Hidrogenio," Ministério de Minas e Energia, 2021.

[311] MIEM, "Green Hydrogen Roadmap in Uruguay," Ministerio de Industria, Energía y Minería, 2022.

[312] MINAE, "Estrategia Nacional de hidrógeno verde," Ministerio de Ambiente y Energía de Costa Rica, San José, 2022.

[313] "Hub Transformacional de Hidrógeno Verde de Panamá," Ministry of Presidency, Panama, 2022.

[314] "Strategia Nazionale Idrogeno Linee Guida Preliminari," Ministero dello sviluppo economico, Italy, 2020.

[315] "Draft Roadmap for production and use of hydrogen in Ukraine," UNECE, 16 03 2021. [Online]. Available: https://unece.org/sed/documents/2021/03/reports/draft-roadmap-production-and-use-hydrogen-ukraine-report. [Accessed 07 10 2021].

[316] IEA, "Hydrogen and Fuel Cells," International Energy Agency, Paris, 2004.

[317] IEA, "Prospects for hydrogen and Fuel Cells," International Energy Agency, Paris, 2005.

[318] IEA, "Hydrogen Production and Storage," International Energy Agency, Paris, 2006.

[319] IEA, "Technology Roadmap - Hydrogen and Fuel Cells," International Energy Agency, Paris, 2015.

[320] Hydrogen Council, "Hydrogen scaling up: A sustainable pathway for the global energy transition," Hydrogen Council and McKinsey & Company, 2017.

[321] Fuel Cells and Hydrogen 2 Joint Undertaking, "Hydrogen Roadmap Europe: a sustainable pathway for the European energy transition," Publications Office of the European Union, Luxembourg, 2019.

[322] WEC, "Innovation Insights Brief - New Hydrogen Economy - Hype or Hope?," World Energy Council , London, 2019.

[323] Pawelec, G, M. Muron, J. Bracht, B. Bonnet-Cantalloube and A. B. N. Floristean, "Clean Hydrogen Monitor 2020," Hydrogen Europe Intelligence Department, 2020.

[324] IRENA, "Green hydrogen: A guide to policy making," International Renewable Energy Agency, Abu Dhabi, 2020.

[325] BloombergNEF, "Hydrogen Economy Outlook: Key messages," BloombergNEF, Singapore , 2020.

[326] Hydrogen Council, "Hydrogen decarbonization pathways: A life-cycle assessment," Hydrogen Council and McKinsey & Company, 2021.

[327] IEA, "Hydrogen in North-Western Europe: A vision towards 2030," International Energy Agency, Paris, 2021.

[328] Hydrogen Europe, "Hydrogen- a carbon-free energy carrier and commodity," Ad van Wijk in partnership with Hydrogen Europe, 2021.

[329] Hydrogen Europe, "Hydrogen enabling a zero-emission society," Hydrogen Europe, 2021.

[330] IEA, "Hydrogen in Latinamerica," International Energy Agency, Paris, 2021.

[331] IRENA, "A Pathway to Decarbonise the Shipping Sector by 2050," International Renewable Energy Agency, Abu Dhabi, 2021.

[332] IRENA, "Decarbonising End-use Sectors: Practical insights on green hydrogen," International Renewable Energy Agency, Abu Dhabi, 2021.

[333] "Making renewable hydrogen cost-competitive. Policy instruments for supporting green H_2," Agora Energiewende and Guidehouse, Berlin, 2021.

[334] "No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe," Agora Energiewende and AFRY Management Consulting, Berlin, 2021.

[335] WEC, "Innovation Insights Briefing: Hydrogen on the Horizon: Ready, Almost Set, Go?," World Energy Council, 2021, 2021.

[336] WEC, "Working Paper | Hydrogen on the Horizon: Inputs from Senior Leaders on Hydrogen Developments," World Energy Council, London, 2021.

[337] WEC, "Working Paper | Hydrogen on the Horizon: Hydrogen Demand and Cost Dynamics," World Energy Council, London, 2021.

[338] H. Council, "Hydrogen Insights An updated perspective on hydrogen investment, market development and momentum in China," Hydrogen Council and McKinsey & Company, 2021.

[339] H. Council, "Policy Toolbox for Low Carbon and Renewable Hydrogen," Hydrogen Council, 2021.

[340] H. Council, "Hydrogen decarbonization pathways," Hydrogen Council, 2021.

[341] H. Council, "Hydrogen for Net-Zero A critical cost-competitive energy vector," Hydrogen Council and McKinsey & Company, 2021.

[342] F. Ausfelder, E. Herrmann and L. López-González, "Perspective Europe 2030 Technology options for CO2- emission reduction of hydrogen feedstock in ammonia production," DECHEMA Gesellschaft für Chemische Technik und Biotechnologie e.V, Frankfurt am Main, 2022.

[343] IEA, "Electrolysers," International Energy Agency, Paris, 2022.

[344] IRENA, "Decarbonising End-use Sectors: Green Hydrogen Certification," International Renewable Energy Agency, Abu Dhabi, 2022.

[345] IRENA, "Green Hydrogen for Industry: A guide to Policy Making," International Renewable Energy Agency, Abu Dhabi, 2022.

[346] IRENA, "Geopolitics of the Energy Transition: The Hydrogen Factor," International Renewable Energy Agency, Abu Dhabi, 2022.

[347] A. van Wijk, K. Westphal and J. Braun, "How to deliver on the EU Hydrogen accelerator," Hydrogen Europe, Brussels, 2022.

[348] "Global Hydrogen Flows: Hydrogen trade as a key enabler for efficient decarbonization," Hydrogen Council and McKinsey & Company, 2022.

[349] "Hydrogen Insights 2022 An updated perspective on hydrogen market development and actions required to unlock hydrogen at scale," Hydrogen Council and McKinsey & Company, 2022.

[350] Hydrogen Europe; The smarter E Europe;, "STEEL FROM SOLAR ENERGY A Techno-Economic Assessment of Green Steel Manufacturing," Hydrogen Europe , 2022.

[351] Clean Hydrogen Joint Undertaking, "Strategic research and innovation agenda 2021-2027," Clean Hydrogen Partnership with European Union, 2022.

A. Appendix

Table A.1 Hydrogen National Plans, Strategies and Roadmaps released until the end of 2022

Country	**Year**	**Month**	**Name**	**Reference**
Japan	2017	December	First country to establish a Hydrogen National Strategy	[278]
France	2018	June	Hydrogen Deployment Plan	[279]
South Korea	2019	January	Hydrogen Economy Roadmap	[280]
New Zealand		September	A vision for Hydrogen	[281]
Australia		November	National Hydrogen Strategy	[282]
The Netherlands	2020	April	Government Strategy on Hydrogen	[283]
Portugal		May	National Hydrogen Strategy	[284]
Norway		June	Norway´s Hydrogen Strategy	[285]
Germany		June	National Hydrogen Strategy	[89]
European Union		July	A Hydrogen Strategy for a climate-neutral Europe	[286]
France		September	National Hydrogen Strategy	[287]
Spain		October	Hydrogen Roadmap: a commitment to renewable Hydrogen	[288]
Russia		October	National Hydrogen Roadmap	[289]
Finland		October	National Hydrogen Roadmap - Business	[290]
Chile		November	National Hydrogen Strategy	[291]
The United States of America		November	Hydrogen Program Plan - draft	[292]
Canada		December	Canada´s Hydrogen Strategy	[293]
Scotland		December	Scottish Hydrogen Assessment	[294]

Sweden	2021	January	Hydrogen Strategy for fossil-free competitiveness-Bussiness	[295]
India		February	National Hydrogen Mission	[296]
Hungary		May	National Hydrogen Strategy	[297]
Paraguay		June	Towards the Green Hydrogen Roadmap in Paraguay	[298]
Slovakia		June	National Hydrogen Strategy	[299]
Czech Republic		July	Hydrogen Strategy	[300]
United Kingdom		August	UK Hydrogen Strategy	[301]
Morocco		August	National Hydrogen Strategy	[302]
Colombia		October	National Hydrogen Roadmap	[303]
Belgium		October	Federal Hydrogen Vision and Strategy	[304]
South Africa		November	Hydrogen Society Roadmap	[305]
Poland		December	Polish Hydrogen Strategy 2030	[306]
Denmark	2022	January	The Government´s Strategy for POWER-TO-X	[57]
Croatia		March	Hydrogen strategy of the Republic of Croatia until 2050	[307]
China		April	Hydrogen industry development plan (2021-2035)	[308]
Austria		June	Hydrogen Strategy for Austria	[309]
Brazil		June	Hydrogen National Plan approved	[310]
Uruguay		July		[311]
Costa Rica		December	National Green H_2 Strategy	[312]
Panama	In preparation		First phase of the Hydrogen Roadmap in January 2022	[313]

Italy			Italian Hydrogen Strategy: preliminary guidelines released in November 2020	[314]
Ukraine			Draft Roadmap for production and use of hydrogen in Ukraine in March 2021	[315]

Table A.2 Hydrogen-related reports from International Energy Agency (IEA), International Renewable Energy Agency (IRENA), World Energy Council (WEC), Hydrogen Council (HC), Hydrogen Europe (HE) and Mckinsey&Company (HC & McKinsey Company), Fuel Cells and Hydrogen Joint Undertaking (FC&HJU)

Year	Number of reports	Author	Ref.
2004	Hydrogen and Fuel Cells	IEA	[316]
2005	Prospects for hydrogen and Fuel Cells	IEA	[317]
2006	Hydrogen Production and Storage	IEA	[318]
2015	Technology Roadmap - Hydrogen and Fuel Cells	IEA	[319]
2017	Hydrogen scaling up: A sustainable pathway for the global energy transition	HC & McKinsey Company	[320]
2018	Hydrogen from renewable power: technology outlook for the energy transition	IRENA	[5]
2019	Hydrogen: a renewable energy perspective	IRENA	[15]
	The future of hydrogen	IEA	[6]
	Hydrogen Roadmap Europe: a sustainable pathway for the European energy transition	FC&HJU	[321]
	Innovation Insights Brief - New Hydrogen Economy - Hype or Hope?	WEC	[322]
2020	Green hydrogen cost reduction: scaling up electrolysis to mee the 1.5°C climate goal	IRENA	[95]
	The Strategic Road Map for Hydrogen and Fuel Cells - Industry-academia-government action plan to realize a “Hydrogen Society”	Hydrogen and Fuel Cell Strategy Council	[20]
	Clean Hydrogen monitor 2020	HE	[323]
	Green hydrogen: A guide to policy making	IRENA	[324]
	The dawn of green hydrogen: Maintaining the GCC’s edge in a decarbonized world	Strategy&PwC	[31]
	Hydrogen Economy Outlook: Key messages	BloombergNEF	[325]
	Path to Hydrogen Competitiveness: A Cost Perspective	HC	[120]
2021	12 insights on hydrogen	Agora	[30]
	Global Hydrogen Review	IEA	[11]

	Hydrogen decarbonization pathways: A life-cycle assessment	HC & McKinsey Company	[326]
	Hydrogen insights: A perspective on hydrogen investment, market development and cost competitiveness	HC & McKinsey Company	[114]
	Hydrogen in North-Western Europe: A vision towards 2030	IEA	[327]
	Innovation outlook renewable methanol	IRENA	[9]
	Green hydrogen supply: A guide to policy making	IRENA	[144]
	Hydrogen- a carbon-free energy carrier and commodity	HE	[328]
	Hydrogen enabling a zero-emission society	HE	[329]
	Ammonia Technology Roadmap Towards more sustainable nitrogen fertiliser production	IEA	[8]
	Hydrogen in Latinamerica	IEA	[330]
	A Pathway to Decarbonise the Shipping Sector by 2050	IRENA	[331]
	Decarbonising End-use Sectors: Practical insights on green hydrogen	IRENA	[332]
	Making renewable hydrogen cost-competitive. Policy instruments for supporting green H_2	Agora	[333]
	No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe	Agora	[334]
	Innovation Insights Briefing: Hydrogen on the Horizon: Ready, Almost Set, Go?	WEC	[335]
	Working Paper | Hydrogen on the Horizon: Inputs from Senior Leaders on Hydrogen Developments	WEC	[336]
	Working Paper | Hydrogen on the Horizon: Hydrogen Demand and Cost Dynamics	WEC	[337]
	Working Paper | Hydrogen on the Horizon: National Hydrogen Strategies	WEC	[29]
	Hydrogen Insights An updated perspective on hydrogen investment, market development and momentum in China	HC & McKinsey Company	[338]
	Policy Toolbox for Low Carbon and Renewable Hydrogen	HC	[339]
	Hydrogen decarbonization pathways	HC	[340]
	Hydrogen for Net-Zero A critical cost-competitive energy vector	HC & McKinsey Company	[341]
2022	Global hydrogen review, IEA	IEA	[18]
	Perspective Europe 2030 Technology options for CO2-emission reduction of hydrogen feedstock in ammonia production	DECHEMA	[342]
	Hydrogen Supply	IEA	[253]
	Electrolyzers	IEA	[343]
	Hydrogen	IEA	[121]

	Decarbonising End-use Sectors: Green Hydrogen Certification	IRENA	[344]
	Green Hydrogen for Industry: A guide to Policy Making	IRENA	[345]
	Geopolitics of the Energy Transition: The Hydrogen Factor	IRENA	[346]
	How to deliver on the EU Hydrogen accelerator	HE	[347]
	Global Hydrogen Flows: Hydrogen trade as a key enabler for efficient decarbonization	HC & McKinsey Company	[348]
	Hydrogen Insights 2022 An updated perspective on hydrogen market development and actions required to unlock hydrogen at scale	HC & McKinsey Company	[349]
	STEEL FROM SOLAR ENERGY A Techno-Economic Assessment of Green Steel Manufacturing	HE	[350]
	Working Paper: Regional insights into low-carbon hydrogen scale up | World Energy Insights	WEC	[251]
	Clean Hydrogen monitor 2022	HE	[66]
	Strategic research and innovation agenda 2021-2027	Clean H2 Partnership	[351]
2023	Hydrogen patents for a clean energy future	IEA & European Patent Office	[21]
	Towards hydrogen definitions based on their emissions intensity	IEA	[47]