Exploring pathways for Norwegian green hydrogen

− A techno-economic evaluation of value chains for Power-to-Hydrogen from the Norwegian North Sea

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Examensarbete

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Dokumenttitel och undertitel

Utforskande av vägar för norsk grön vätgas – En tekno-ekonomisk utvärdering av värdekedjor för Power-to-Hydrogen från norska Nordsjön.

Sammandrag

Förnybar vätgas kan transporteras i många olika former och genom olika transportsätt. Varje form och transportsätt är förknippad med olika för- och nackdelar relaterat till bl.a. lagringstäthet och förluster. Den pågående expansionen av havsbaserad vindkraft kommer troligtvis sammanlänkas med vätgasproduktion på något sätt och det finns många olika sätt på vilka det kan göras.

Detta examensarbete utreder vilka värdekedjor för Power-to-Hydrogen och Power-to-X som är mest lovande för det norska licensområdet för havsbaserat vindkraft, Sørlige Nordsjø II, under antagande om en investering år 2030. Modellen som användes för att genomföra beräkningarna är ett verktyg för att sätta upp business case-scenarier, och modellen utökades till att inkludera värdekedjesteg nedströms från elektrolysören fram till leverans vid ett industrikluster. Modellen används till att beräkna *levelised cost of hydrogen* för 17 olika värdekedjor, med transport till två olika geografiska platser – Porsgrunn i Norge och Rotterdam i Nederländerna. *Levelised cost* för ammoniak och metanol beräknas också för värdekedjor baserade på dessa vätebärare, för att utvärdera potential för direkt användning av dessa.

Resultaten av jämförelsen av värdekedjor visar att landbaserade och havsbaserade rörledningstransport av komprimerad vätgas är värdekedjorna med lägst *levelised cost of hydrogen* för Porsgrunn och Rotterdam, respektive. Detta gäller för alla osäkerheter och känsligheter som testas i studien. Påverkan på rörledningskostnader av kuperad terräng tas dock inte hänsyn till. Utredningen om potentialen för direkt användning av ammoniak och metanol visar att mer studier krävs för att besvara denna fråga.

Även om studien visar tydliga resultat gällande mest lovande värdekedjor från ett *levelised cost of hydrogen*-perspektiv så ska hänsyn tas till att fler aspekter kan påverka vilka värdekedjor som är mest lovande, så som energieffektivitet, efterfrågan på produkter från närliggande industri och investeringsflexibilitet.

Nyckelord

Vätgas, Ammoniak, Metanol, Power-to-Hydrogen, Power-to-X, bedömning av värdekedjor

Title and subtitle

Exploring pathways for Norwegian green hydrogen – A techno-economic evaluation of value chains for Power-to-Hydrogen from the Norwegian North Sea

Abstract

Renewable hydrogen can be transported using different hydrogen carriers and modes of transport. Each carrier and mode is associated with different drawbacks and benefits relating to – among other factors – storage density and losses. The forthcoming expansion of offshore wind is likely to be coupled with hydrogen production in some way and there are many different ways that this can be done.

This master thesis investigates what value chains for Power-to-Hydrogen and Power-to-X that are most promising for the Norwegian offshore wind licensing area Sørlige Nordsjø II, assuming an investment in 2030. The model used to perform the necessary calculations is a proprietary business case scenario builder that was extended to include value chain steps downstream of the electrolyser up to delivery at an industrial cluster. The model is used to calculate the levelised cost of hydrogen for 17 different value chains, involving transport to two different geographical locations – Porsgrunn in Norway and Rotterdam in the Netherlands. The levelised cost of ammonia and methanol is also calculated for value chains based on these carriers, to evaluate the potential of direct utilisation of these chemicals.

The results of the value chain comparison show that onshore and offshore pipeline transport of compressed hydrogen are the value chains with lowest levelised cost of hydrogen for Porsgrunn and Rotterdam, respectively. This holds for all uncertainties and sensitivities tested within the thesis. The impact on pipeline costs of hilly terrain is, however, not considered in the study. The investigation of potential for direct utilisation of ammonia and methanol shows that more studies are required to answer this question.

Although the study shows clear results regarding the most promising value chains from a levelised cost of hydrogen-perspective, recognition is given to the fact that more aspects might affect which value chain is more promising, such as energy efficiency, demand for the products from nearby industries and investment flexibility.

Keywords

Hydrogen, Ammonia, Methanol, Power-to-Hydrogen, Power-to-X, Value chain assessment

Preface

This report is a master thesis undertaken during the spring semester of 2021 as part of the MSc in Environmental Engineering at Lund University, Faculty of Engineering, LTH. It was completed in collaboration with the unit of Energy Markets & Technology at DNV, Oslo.

First, I want to thank my friends and family for all the support they have given me during this process. Writing a master thesis on your own can be challenging in many ways, but during my toughest periods you have been there to help me remember that even though some things feel bad, other things are certainly not.

In the early parts of my process, before having found a clear direction of my work, I had the privilege of having Göran Loman as a mentor and guide through the world of wind power industry. Thanks, Göran, for taking this time to support me in my process!

I also want to express my gratitude to my co-supervisor at DNV, Magnus Killingland, for taking your time to help me through this thesis work. Having you as a link from the academic to the business world has been very helpful and has also given me good inspiration for my work.

Most of all, I want to extend my thanks to my supervisor at LTH, Lars J Nilsson. The amount of time you have dedicated to supervising me through this semester has been truly helpful for me. Having you as a sounding board has helped me finding the way through the academic process, you have been an incredible support for me during the whole semester. Most importantly, though, talking to you have has given me a great deal of fun conversations, outside the academic discussions.

Lastly, thanks to Tommy Körberg, Solala and Voctave for providing me with musical comfort during these months. I am certain this report will cross your path at some point.

– Theo Nyberg –

Terminology

CAPEX   Capital expenditures

CEPCI   Chemical Engineering Plant Cost Index

CH$_2$ Compressed hydrogen gas

DBT   Dibenzyltoluene

LCOE   Levelised cost of electricity

LCOH   Levelised cost of hydrogen

LH$_2$ Liquid hydrogen

LOHC   Liquid organic hydrogen carrier

MeOH   Methanol

NH$_3$ Ammonia

NPV   Net present value

OPEX   Operational expenditures

OSWF   Offshore wind farm

P2H   Power-to-hydrogen

P2X   Power-to-X

PSA   Pressure swing adsorption

TRL   Technological readiness level

1 Introduction

The last year has been dominated by the global crisis caused by the outbreak of COVID-19, but this has not diminished the urgency of the global climate crisis. In the current situation, the world is heading for increased risk that annual average global temperatures exceed 1.5°C (UK Met Office 2021), despite the goals of "*well below 2°C*" and "*pursuing efforts*" to 1.5°C accepted by 196 countries in the Paris Agreement (UNFCCC 2015). Norway is one of the countries that adopted the agreement, and after having submitted a first nationally determined contribution for emission reductions of 40% by 2030, this was updated in 2020 to a goal of reducing emissions by "*at least 50% and towards 55% compared to 1990 levels by 2030*" (UNFCCC 2020b). For the longer timeframe, Norway has set up a goal of reducing emissions by 90-95% by 2050 (UNFCCC 2020a). To fulfil these goals Norway is cooperating with the EU, who recently increased its ambitions to at least 55% emission reductions by 2030, with the longer-term goal of climate-neutrality by 2050 (BBC News 2021).

As part of the efforts to fulfil climate targets both the EU and Norway have in the last year released hydrogen strategies. In these, hydrogen is envisioned as having significant potential for reducing emissions, especially by offering a solution to decarbonise industrial processes and economic sectors where emission reductions are otherwise hard to achieve (EU, 2020a). The strategies also stress the importance of how hydrogen is produced, for it to contribute to climate neutrality. Today 90% of hydrogen used in Europe is produced using natural gas (OED & KLD, 2020), leading to greenhouse gas emissions of approximately 80 Mt CO_2[1]. In the EU and Norway strategies, two main pathways of producing low-emission hydrogen are outlined. Conventional production from natural gas, but where emissions are prevented using carbon capture and storage (CCS), offers a source of blue hydrogen, while green hydrogen is produced with electrolysis powered by renewable electricity. The EU strategy sets a priority on green hydrogen, but points to the short- and medium-term role of blue hydrogen (EU, 2020a). The Norwegian strategy points to both these as important for reaching the national climate goals (EU, 2020a).

Coupling renewable power, such as wind or solar, with hydrogen production does not only give a green source of hydrogen, but also helps mitigate the variability which is often depicted as a negative aspect of wind and solar power. For the hydrogen, the variability of these power sources also offers an opportunity in terms of production costs. Weather-dependent power production often causes periods of surplus supply, giving lower power prices. Hydrogen can benefit from this aspect of the power supply, by focusing production to times when electricity prices are lower.

Close to the release of the Norwegian hydrogen strategy, Norway's ministry for oil and energy announced that the government is opening two areas for development of offshore renewables (OED, 2020). With the planned development of offshore wind from these sites and with the Norwegian hydrogen strategy in mind, the opportunity to produce hydrogen from these offshore wind farms is of interest. However, as outlined in the Norwegian hydrogen strategy, focus should not only be on how hydrogen is produced but rather looking at whole value chains for hydrogen, considering the total costs of production and transport to the consumer (OED & KLD, 2020).

Hydrogen produced from a large-scale electrolyser can take many different forms and be transported in different ways. It could for instance be stored and transported as pressurised gas, liquified hydrogen,

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[1] Own calculation assuming that 90% of the 9.7 Mt hydrogen used in Europe annually (Kakoulaki et al. 2021) is produced with a carbon footprint of 9.2 kg-CO_2/kg-H_2 (Hydrogen Council 2021a).

converted to ammonia or some other hydrogen carrier. It could take different routes as being produced and converted close to the offshore windfarm or close to the end-user. Different solutions require different infrastructure setups and are more or less suited for different end-uses.

In previous studies Sekkesætter (2019) compared concepts and systems for processing and marine transportation of hydrogen. Ishimoto et al. (2020) analysed and compared hydrogen value chains from northern Norway to Japan and Rotterdam, including the whole value chains from production to market delivery of hydrogen either as ammonia or liquid hydrogen. Niermann et al. (2019; 2019; 2021) assessed value chains for different liquid organic hydrogen carriers (LOHC), comparing these to value chains based on compressed or liquid hydrogen. Wulf and Zapp (2018) used Life Cycle Analysis and Life Cycle Costing to compare hydrogen transport using LOHCs to liquid hydrogen. Franco et al. (2021) performed a techno-economic assessment of different offtake pathways for hydrogen produced from offshore windfarm to an onshore import terminal.

These previous studies have compared concepts and value chains for hydrogen production, processing and delivery. However, no previous studies have been made on these issues in the specific Norwegian context of developed offshore wind power. Furthermore, none of them have explicitly considered and discussed the direct use of hydrogen carriers. It is with this background that the purpose of this study has been set up.

1.1 Purpose and research questions

This thesis studies value chains for Power-to-Hydrogen (P2H) and Power-to-X (P2X) for the Norwegian offshore wind site Sørlige Nordsjø II. *Value chains* refer to the different steps from the production of electricity and hydrogen, conversion to hydrogen carriers to the storage and transport to end-point. The purpose is to investigate what value chains that are most promising from a techno-economic perspective, considering both hydrogen, ammonia and methanol as possible end-products. This is done by answering the following research questions:

- Are there any value chains that are more promising than the others in terms of levelised cost of hydrogen?
- Is there any difference between value chains in the division of costs between capital expenditures and operational expenditures?
- How does the possibility of direct utilisation of ammonia and methanol affect the potential of value chains based on these hydrogen carriers?

1.2 Study outline

The work process to produce this report has consisted of different steps. The first was to perform a background study with the aim of exploring different hydrogen carriers and transport modes, described in the background section. The knowledge gathered from this work was then used to develop the business case scenario builder used for doing the main calculations. A data collection was performed to find data necessary for the model calculations. A set of value chains was defined and then studied using the business case scenario builder, including testing of uncertainties and sensitivities. The results were benchmarked against results of similar studies to put them in a context. These results were then analysed and discussed, in relation to the research questions and the purpose of the thesis.

The report is structured in the following way: first a background to the development of offshore wind power and green hydrogen is given, followed by a technical background of the different steps in the hydrogen value chains. This is followed by a description of the methods used in the thesis, covering how data collection has been performed and how the model is built up. Next comes the section presenting the main results of the study, integrated with an analysis of these. In the following discussion the main take-aways are discussed and connected to purpose of the study and the wider context. Lastly, the conclusion summarises the findings of the study.

2 Background

2.1 The policy setting

2.1.1 A boom of hydrogen strategies

During the last couple of years hydrogen has gone from being an interesting but expensive technology to being seriously considered as a necessary tool for meeting the climate goals. In 2020 nine countries released hydrogen strategies, which together with the already existing ones make it 13[1]. An additional 11 countries were preparing drafts during 2020 and could release their strategies this year, which could make it to 24 countries in total. Also, the EU released its hydrogen strategy in which it requires member states to formulate their own national versions. The strategies set up goals for deployment of electrolysers, with the goals of EU and Chile alone amounting to 65 GW by 2030 (EU, 2020a; Ministry of Energy 2020). This should be seen in relation to the current installed capacity which is less than 1 GW globally.

2.1.2 The importance of net-zero targets

The rise of hydrogen on the agenda can be seen in the light of more countries adopting net-zero emission targets, making it clear that also hard-to-abate sectors will have to decarbonise. This presents an opportunity for hydrogen to provide the solution in sectors like the steel, ammonia, refinery and chemical industry, where there is a lack of alternative decarbonisation options (Agora Energiewende and AFRY Management Consulting 2021).

2.1.3 Blue or green hydrogen?

An important distinction within policy is between different hydrogen production methods, where green often refers to hydrogen produced through electrolysis from renewable power and blue refers to hydrogen produced from natural gas combined with carbon capture and storage (CCS). In the EU strategy green hydrogen is lifted as the long-term solution, with blue hydrogen seen as a transition solution (EU, 2020a). In the Norwegian strategy, on the other hand, both solutions are promoted more equally (OED & KLD, 2020). An important policy decision here - at least for the European context - is that which will be taken around the delegated acts of the EU Taxonomy. The Taxonomy is the policy framework set up by the EU to set common standards for sustainable finance, and the delegated acts are the part of this in which the distinction between sustainable and unsustainable production methods is

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[1] Netherlands, Portugal, Norway, Germany, EU, France, Spain, Chile, Italy, Canada released strategies or drafts for it in 2020. Japan, South Korea and Australia had strategies since before. UK, Sweden, Austria, Russia, China, New Zeeland, Oman, Morocco and Paraguay are preparing drafts.

made. In the latest proposal revealed on April 21 this year a carbon footprint of 3.0 kg CO_{2eq}/kg H_2 was suggested and if the delegated act is accepted by the EU Commission in June, this is what will be the threshold (EU 2021). With this threshold, so-called blue hydrogen might also count as sustainable[1] and thus compete on more equal terms with green hydrogen. The position held by major actors such as the EU can play a large role for what capital is available for investments, but also for what forms of hydrogen that are demanded by companies. By extension, it can thus affect both the capital cost for investments and the price premium that blue and green hydrogen gets over grey hydrogen[2].

2.2 Offshore wind and Power-to-Hydrogen

2.2.1 Wind power continues its journey

One of the main driving forces that have contributed to making hydrogen a viable decarbonisation option is the falling prices in renewable electricity production. Electricity prices together with the cost of electrolysers make up most of the costs for renewable hydrogen (IRENA 2020b) and a price fall in renewable electricity thus helps in decreasing the price of hydrogen. Electricity generated from wind power in Europe more than tripled from 2009 to 2019 (IEA 2019c), and this development is set to continue as installed wind capacity increases (Wind Europe 2020). Figure 2.1 shows the cost reductions that has come with this deployment, as well as projections of future reductions. While the majority of wind power growth so far has been within onshore wind, offshore wind is now seriously joining the race. In its Offshore Renewable Energy Strategy released in November 2020, the EU proposes an increase of Europe's offshore wind capacity from the current level of 12 GW to 60 GW by 2030 and 300 GW by 2050 (EU 2020b). Much of this expansion is expected to take place in the North Sea, which is already the world's leading region in deployed capacity (EU 2020b). Norway has no goals in terms of capacities of increased offshore wind power, but as part of the same development Norway recently announced that two areas in the Norwegian part of the North Sea are opened for development of offshore renewables (OED 2020). One of these areas - Utsira Nord - is, due to its deep waters, suited for floating wind power while the other - Sørlige Nordsjø II - can also host bottom-fixed wind power.
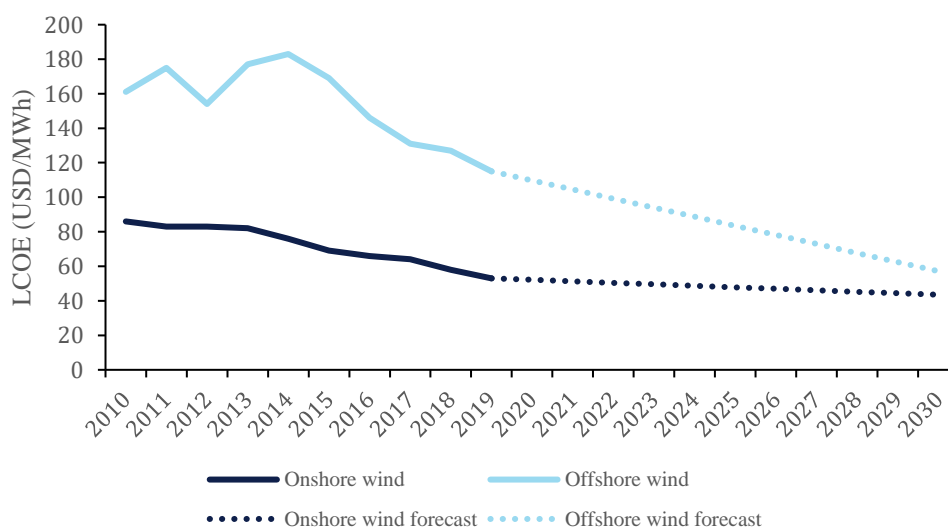
Figure 2.1. Historic cost and projected cost reductions until 2030. Sources: IRENA (2020a, 2020c).

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[1] Steam methane reforming with a carbon capture rate of 75% and natural gas transported from Norway 1700 km to the German or Dutch North Sea coast has greenhouse gas emissions amounting to 2.7 kg CO_{2eq}/kg H_2 (Hydrogen Council 2021a).
[2] Steam methane reforming without carbon capture and natural gas transported from Norway 1700 km to the German or Dutch North Sea coast has greenhouse gas emissions amounting to 9.2 kg CO_{2eq}/kg H_2 (Hydrogen Council 2021a).

2.2.2 Wind power's loss...

While the development within wind power offers a great opportunity for decarbonising the electricity systems it does not come without challenges. When the electricity mix comes more and more from variable energy sources such as wind and solar power, the task of keeping the electricity system in balance becomes more difficult. This can lead to increased costs for keeping the system in balance, but ultimately also risk leading to an electricity system that is less resilient to disturbances. Another issue with increasing amounts of wind power is the concept of price cannibalisation, which is related to the fact that wind turbines, unsurprisingly, produce power when the wind blows. With increasing zero marginal cost variable electricity sources in the power mix, power prices are pressed downwards, leading to less revenue for the existing generators on that market (López Prol, Steininger, and Zilberman 2020).

### 2.2.3 ...is hydrogen's gain

These two limitations of a system with much wind power present an opportunity for hydrogen. If wind parks are also connected to electrolysers, a way to handle both these problems is at hand. Electrolysers can provide balancing services by increasing and decreasing production according to the demands of the grid, also offering an extra income source (Dyab et al. 2021). At sufficiently high hydrogen prices, hydrogen production connected to a wind farm could also increase the profitability of a wind farm by producing and selling hydrogen at times of lower prices (McDonagh et al. 2020).

3 Hydrogen value chains

This section gives the theoretical background to the different steps of the hydrogen value chain, including the production of green hydrogen, different hydrogen forms and carriers, transport modes and storage solutions. These are the components used in the value chain assessment described in Method and Results & analysis. Offtake of hydrogen, ammonia and methanol is also included as the last part of this section, although this step is not included in the value chain assessment.

3.1 Green hydrogen

Water electrolysis is the process of splitting water molecules into hydrogen and oxygen gas, according to the reaction formula in Equation 3.1.

$$2H_2O + \text{electricity} \rightarrow 2H_2 + O_2 + \text{heat} \qquad \text{Equation 3.1}$$
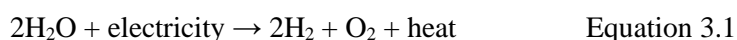
Production of hydrogen through electrolysis is not a new concept, with Norsk Hydro using alkaline eletrolysers to produce hydrogen for its ammonia production already in the 1920s (Alfa Laval et al. 2020). However, with recent decreases in electrolyser CAPEX combined with the previously mentioned development within renewables, the price of producing renewable hydrogen is starting to close the gap to conventional grey hydrogen as can be seen in the projections in Figure 3.1.
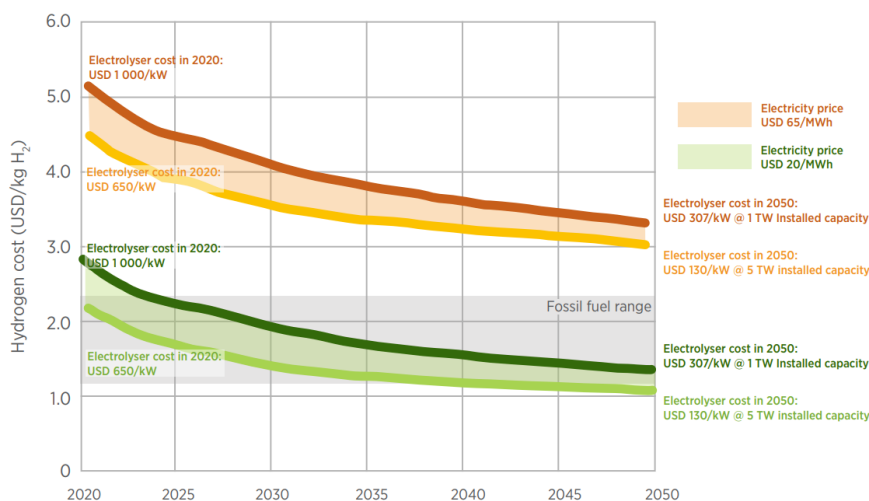
Figure 3.1. Cost of green hydrogen as a function of electrolyser deployment, using an average (64 $/MWh) and low (20 $/MWh) electricity price, constant over the period 2020-2050. Source: (IRENA 2020b).

3.1.1 Electrolyser technologies

There are different technologies that can be used for producing hydrogen with electrolysis. The most relevant technologies to date include alkaline, proton exchange membrane (PEM), solid oxide and anion exchange membrane electrolysers. Alkaline is the most mature of the three, but with PEM advancing quickly, mainly thanks to its higher flexibility making it more suitable to coupling with renewable power sources (IEA 2019b). Solid oxide and anion exchange membrane electrolysers offer promising technology improvements but are currently only available at lab scale (IRENA 2018) and, considering the time horison of this study they are not considered within the scope.

Alkaline electrolysers

Alkaline electrolysers are the most mature technology for water electrolysis and thus currently have the lowest average CAPEX per capacity (IRENA 2018). Apart from lower capital costs alkaline electrolysers also benefit from having a longer lifetime, with proven lifetimes of over 30 years (IRENA 2020b). Output pressures range from 1 to 30 bar (IEA 2019b).

PEM electrolysers

While currently at a lower maturity level than alkaline electrolysers, PEM electrolysers are emerging quickly. One of the main reasons for this is their ability to operate with more flexibility, offering a wider operating range and a shorter response time (IRENA 2018). This aspect is important when coupling the electrolysers to variable energy sources as well as quickly fluctuating electricity markets, and it also makes it easier for electrolysers to provide frequency control services for the grid (IRENA 2018). Another benefit of PEM electrolysers is that they typically produce hydrogen at higher output pressures than alkaline electrolysers[1], meaning that less compression is needed downstream of the electrolyser (IRENA 2018).

3.1.2 Scaling up

Currently the largest electrolysers being installed and announced are in the orders of tens of megawatts (FuelCellsWorks 2020; Recharge News 2021) while plans include projects in the scale of hundreds of

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[1] PEM output pressures today are typically 30 bar but could increase to 80 bar in the future (IEA 2019b).

megawatts or even gigawatt scale. To understand how this scale up is supposed to happen it is necessary to have some grasp of the different system levels of an electrolyser plant. These can be divided into cell, stack, module and plant.

Cell

The core of the electrolyser is known as the cell, which is where the electrochemical process of splitting water into H_2 and O_2 takes place. It consists of two electrodes (anode and cathode) submersed in a liquid electrolyte or separated by a solid electrolyte membrane, two porous transport layers and bipolar plates that provide mechanical support and distributes flow. (IRENA 2020b)

Stack

Stack is the term for several cells connected in series, also including components such as insulation between opposite electrodes, mechanical support frames and endplates preventing leakage (IRENA 2020b). For PEM electrolysers the largest stacks to date include Cummin's 2.5 MW stack[1], to the knowledge of the author.

Module

As electrolyser manufacturers have been trying to scale up their electrolysers, a practical limit of 100 cells per stack seems to exist, beyond which other issues seem to make further scale-up inefficient (Proost 2020). As a result of this, a modular approach to scale-up is often preferred by manufacturers (Proost 2020). An electrolyser module is a set of stacks grouped together, sharing so-called balance-of-plant systems, including management of electricity, water supply and treatment of hydrogen and oxygen gas (IRENA 2020b).

Plant

The highest system level for an electrolyser is the plant level. A plant could consist of a single stack, a multi-stack module or by several modules grouped together. To this date, the largest electrolyser plant that has been sold is a 24 MW PEM electrolyser that ITM Power will build for Linde in Germany (Recharge News 2021). Reaching scales of hundreds of MWs thus imposes a significant step up, and there are several proposed concepts for how this can be done. ISPT recently proposed a modular design for GW scale plant, including 432 or 1485 alkaline or PEM stacks respectively (2020).

3.2 Hydrogen carriers

Hydrogen in its pure gaseous form has a low energy density, making it inefficient to store and transport in larger volumes and for larger distances (IEA 2019b). This has led to various hydrogen carriers being explored, aiming to find other forms of hydrogen with higher energy density that are also easier to handle. One alternative is to increase the energy density by liquifying the hydrogen gas, but it could also be converted or absorbed into other molecules including ammonia, methanol or so-called *liquid organic hydrogen carriers*.

In this study five different forms of hydrogen are considered: compressed hydrogen (CH_2), liquid hydrogen (LH_2), ammonia (NH_3) methanol (MeOH) and a liquid organic hydrogen carrier (LOHC). In the following sections their physical characteristics as well as technology for their conversion and

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[1] https://flexnconfu.eu/wp-content/uploads/2020/11/Webinar-FLEXnCONFU_Cummins_D_Thomas.pdf

reconversion are described. The scope is limited to these five carriers due to time limitations, but others, including methane and a number of LOHCs apart from the one considered here, are also possible.

3.2.1 Compressed hydrogen

The hydrogen that comes out of an electrolyser can have different pressures and temperatures, depending on the electrolyser technology. Alkaline electrolysers can today produce hydrogen at pressures up to 15 bar (30 bar in the long run) while PEM electrolysers typically have as high pressures as 30 bar (60 bar in the long run) (IRENA 2018, 2019). However, for storage and transport of hydrogen in gaseous form higher pressures are required to reach sufficient energy densities and thus extra compression is necessary. Hydrogen at 300 bar 20°C has a density of around 20 kg-H_2/m^3 (DNV 2019b).

Hydrogen compression is normally performed using mechanical compression, using either positive displacement compressors or centrifugal compressors (U.S. Department of Energy n.d.). Alternatives to mechanical compression exist – including electrochemical reactions, metal hydrides and ionic liquids – but these are currently at research and development stage (U.S. Department of Energy n.d.). Different levels of compression are possible and used for different purposes, but for truck transport pressures of 200 or 350 bar are common (DNV 2019b; Teichmann, Arlt, and Wasserscheid 2012). Based on a review article on hydrogen compression technologies (Sdanghi et al. 2019), mechanical hydrogen compression is estimated – for the purpose of this thesis – to have a technological readiness level (TRL) of 9[1].

3.2.2 Liquid hydrogen

Another way of increasing the density of hydrogen is to liquify it. This can be suitable for larger scale storage or longer distance transport of hydrogen. However, liquefaction is a complicated process requiring temperatures of -240°C and pressures of 13 bar (Møller et al. 2017). Similarly low temperatures are also required for the storage of liquid hydrogen (IEA 2019b). Liquid hydrogen has a density of 71 kg-H_2/m^3 (DNV 2019b).

Conversion - liquefaction

Hydrogen was liquefied for the first time at the end of the 19th century and today a plethora of different liquefaction methods have been developed (Aasadnia and Mehrpooya 2018). The liquefaction process can be divided into five general steps: compression of the feed; chilling from 20°C to 6°C; pre-cooling down to -143 to -193°C; cryogenic cooling down to -243 to -253°C; final expansion and liquefaction (Essler et al. 2012; Stolzenburg et al. 2013). A simplified flow chart, in which all the above steps are summed up in one step, is presented in Figure 3.2. The liquefaction process has been estimated to TRL 3 (Sekkesæter 2019), but level is likely an underestimation, considering that it is a technology in use already today (Decker 2020; H21 North of England 2018).

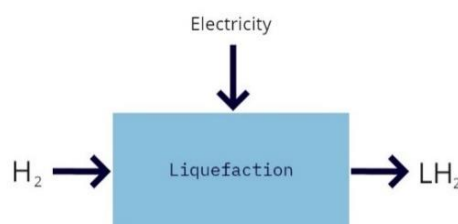

Figure 3.2. Schematic flow chart of conversion to LH2.

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[1] TRL is a measure of the maturity of certain technology, with scale ranging from 1 to 9, with one as the lowest and 9 as the highest maturity level (EU 2014).

One of the main drawbacks with liquid hydrogen is the high energy consumption of the liquefaction process, estimated by various sources to correspond to between 20% and 45% of the hydrogen energy content (Cardella, Decker, and Klein 2017; IRENA 2019; Kamiya, Nishimura, and Harada 2015; Ohlig and Decker 2014; Reuß et al. 2017; Stolzenburg et al. 2013). This energy is supplied as electricity, and while the IDEALHY project claimed that an electricity demand of 6.76 kWh_{el}/kg_{H2} should be possible for that process (Stolzenburg et al. 2013), current technologies typically have a demand above 10 kWh/kg_{H2} with technology improvements and scale-up expected to achieve levels of 7.5-10 kWh_{el}/kg_{H2} on a medium-term future (Ohlig and Decker 2014).

While hydrogen liquefaction is an established and proven technology it is currently in operation only at small scale. The current sizes of hydrogen liquefaction plants that are being installed are in the orders of tens of tons per day, with recently announced plans for the "world's largest liquid hydrogen plant" of 82 t/d (FuelCellsWorks 2021). However, increases in capacities up to 200 t/d are considered achievable and leading to cost reductions (H21 North of England 2018).

Reconversion - regasification

Regasification of hydrogen is possible through a few different technologies. As liquid hydrogen is thermodynamically similar to liquid natural gas (LNG), which is a more established technology, regasification methods can be inspired from those (Laouir 2019). The most common way of LNG regasification is open-rack vaporisation, a technology that could also be applied for liquid hydrogen (Sekkesæter 2019).

A simplified flow sheet of the regasification plant is presented in Figure 3.3. It shows that the vaporisation is preceded by a pressurisation step, both steps which require electricity. Open rack vaporisers use seawater as heat sources to vaporise the hydrogen, and thus makes use of an inexpensive source of energy. Regasification of hydrogen can potentially also be designed to produce power, since the coldness of LH_2 could be used to run a thermal machine, and thus produce electricity (Laouir 2019). The technological readiness level of hydrogen regasification has been estimated to TRL 4 (Sekkesæter 2019).
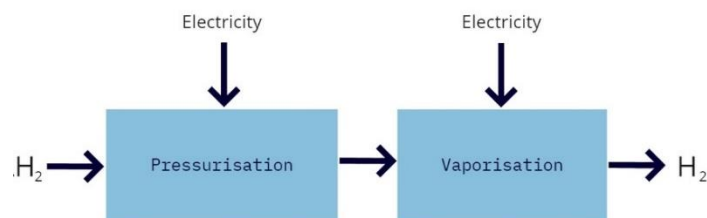
Figure 3.3. Schematic flow chart of reconversion from LH_2.

3.2.3 Ammonia

Ammonia is a colourless gas at ambient conditions with a density lower than air. It has a boiling point of -33.3°C at atmospheric conditions but is liquid at 20°C for pressures above 8.6 bar (DNV 2020). The hydrogen density for liquid ammonia is 121 $kg-H_2/m^3$ (DNV 2020). Ammonia can be corrosive to some materials, like zinc and copper and can also be toxic and can cause lung damage or death at exposure to very high concentrations of gas (DNV 2020).

Conversion – ammonia synthesis

The production of ammonia can be divided into two steps: separation of the feedstock gases and subsequent synthesis of them. Depending on the source for the hydrogen gas, the separation of nitrogen can either be achieved in the same or a separate process.

When hydrogen is produced using water electrolysis, nitrogen must be produced using an air separation unit. There are two major technologies used for air separation of nitrogen: cryogenic air separation and pressure swing adsorption (PSA). Cryogenic air separation is generally more suitable for larger scales since it benefits more from economies of scale, while PSA is more suited for smaller applications (Sekkesæter 2019).

For the synthesis of the gases, the Haber-Bosch process is the dominating method, in which hydrogen gas and nitrogen gas are mixed according to the reaction in Equation 3.2. The reaction typically requires pressures of about 200-300 bar, temperatures of 400-500°C and presence of an iron-based catalyst (Giddey et al. 2017; Yapicioglu and Dincer 2019). There are alternative ways of synthesising the gases to ammonia, mainly by using electrolytic ammonia synthesis, but such methods are not commercially available at a large scale (DNV 2020).

$$N_2 + H_2 \rightarrow NH_3 + heat \qquad \text{Equation 3.2}$$
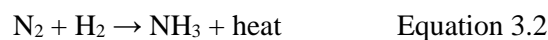
A simplified flow sheet of the process is displayed in Figure 3.4. This flow sheet shows that the process requires energy in the form of electricity for nitrogen separation and compression of the gas mixture and that energy in the form of heat is generated and released from the synthesis of the gases. Using steam turbines, some of the heat energy can be used to drive the compressors (H21 North of England 2018). The process also includes PSA for the separation of nitrogen gas.

Though ammonia synthesis is generally optimised for continuous production, it can also be used for dynamic production (Fuhrmann, Hülsebrock, and Krewer 2013). Start-up of the ammonia synthesis process is both costly and time consuming, and frequent start-ups can also decrease equipment lifetime through thermochemical stress. However, producers of ammonia synthesis plants claim that flexibility ranges of 10-100% are possible (Alfa Laval et al. 2020). Synthesis of ammonia using the Haber-Bosch process has been estimated to TRL 9 (Sekkesæter 2019).

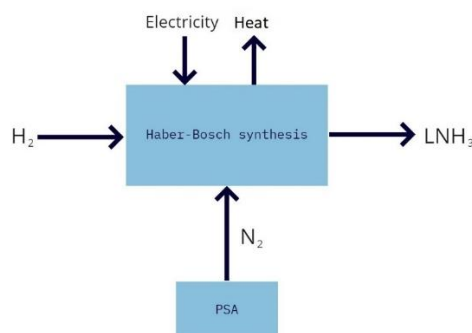Figure 3.4. Schematic flow chart of conversion to NH_3.

Reconversion – ammonia cracking

The process of reconverting ammonia to H_2 and N_2 is called ammonia cracking (also dissociation or splitting) and has been used in industry for a long time. It involves pumping of liquid ammonia to required pressure, evaporation and preheating before the gas is cracked to hydrogen and nitrogen in an

endothermic and catalytic reaction (H21 North of England 2018). Hydrogen can then be separated from the gas mixture using PSA. Incomplete cracking of NH_3 and separation of H_2 means that some H_2 is lost during the process, with total recovery rates of 81% possible (Giddey et al. 2017).

A simplified flow sheet of the ammonia cracking process is shown in Figure 3.5. It shows that some electricity is required for operating the compressors. Also, since ammonia cracking is an endothermic process, it requires energy in the form of heat and the required operating temperature (and thus the heat requirement) depends on the catalyst used (Giddey et al. 2017). Nickel has previously been the dominating catalyst used in the process, but it requires an operating temperature above 900°C. Using more novel catalysts, temperatures below 500°C have been demonstrated to be sufficient (Giddey et al. 2017). The high operating temperature also means that hot gases are generated, making heat recovery an important measure to reach high energy efficiency of the process. If hydrogen is used for heating as much as 20% of the hydrogen can be required, but as the cracked ammonia (hydrogen) feed contains more energy than the ammonia feed, an efficiency of 86% (higher heating value) can still be reached (H21 North of England 2018). Cracking and purification of ammonia has been estimated to TRL 4 (Sekkesæter 2019).
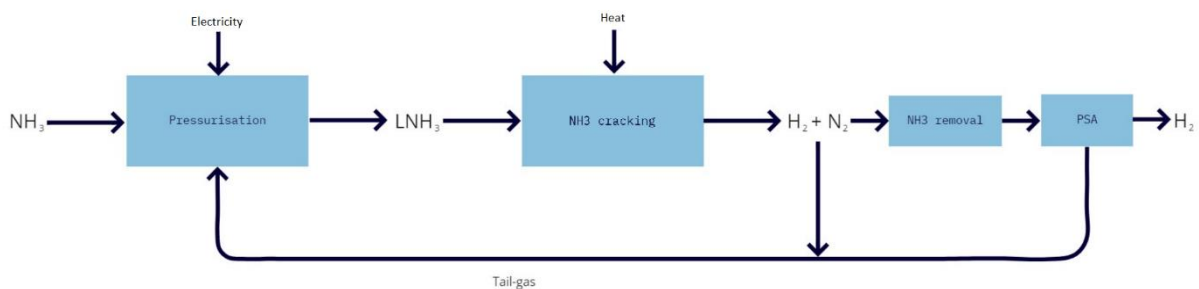

Figure 3.5. Schematic flow chart of reconversion from NH3.

3.2.4   Methanol

Methanol is an alcohol that is liquid under ambient temperatures and pressure, with a hydrogen density of 95.6 kg-H_2/m^3 at normal conditions (Niermann, Beckendorff, et al. 2019). As a hydrogen carrier it benefits both from its high energy and hydrogen density but also from only requiring minor and inexpensive modifications of current infrastructure (IRENA 2021).

Conversion – methanol synthesis

Today, almost all methanol is produced from fossil fuels, mainly natural gas or coal (IRENA 2021). Through reforming or gasification, these fuels are converted to methanol. Renewable electricity can also be used to make methanol, which is then called e-methanol.

E-methanol can be produced in several ways, all using renewable electricity as an energy source. The methanol synthesis process considered in this thesis is the one that can be coupled to water electrolysis. As the reaction formula of the process reveals in Equation 3.3, the reaction leads to one third of the hydrogen being lost as water. Other synthesis technologies have higher conversion efficiencies but have currently not reached the same technological maturity as the process considered here (Goeppert et al. 2014; IRENA 2021; Marlin, Sarron, and Sigurbjörnsson 2018).

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O + \text{heat} \qquad \text{Equation 3.3}$$
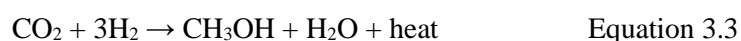
A simplified flow sheet of the methanol synthesis process is shown in Figure 3.6. It shows the three main process steps which are pressurisation, catalytic reaction, separation and distillation. To increase conversion efficiency the unreacted gases are recirculated, but a purge stream is also necessary to prevent build-up of inert gases. As the figure shows, energy in the form of electricity is required for the synthesis. The process builds on an exothermic reaction, giving a net excess of heat. Heat is needed for internal steps, but by integration of the heat exchange network this can be covered from hot streams within the plant. However, cooling water is still required for the process and must be supplied from outside of the plant. The synthesis of methanol has been estimated to TRL 9 (Niermann, Beckendorff, et al. 2019).
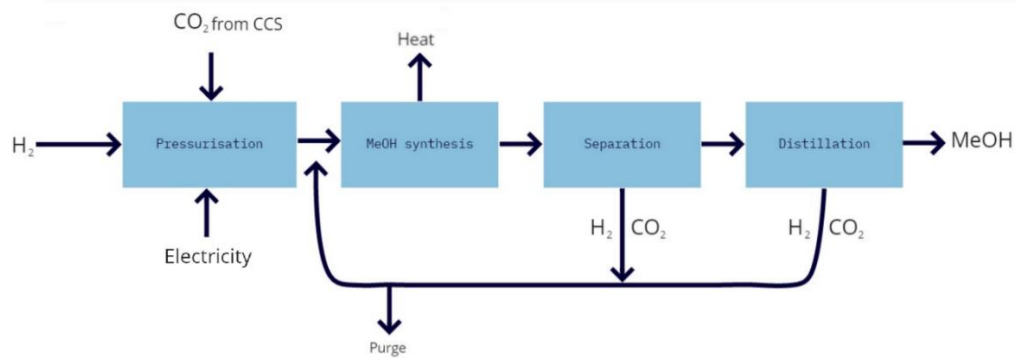

Figure 3.6. Schematic flow chart of conversion to MeOH.

Reconversion – methanol dehydrogenation

Methanol can be processed to release hydrogen in a reaction that also releases carbon as CO_2 and CO. This can be achieved in various ways, including high-temperature steam reforming and low-temperature dehydrogenation, associated with different release times of the hydrogen. For steam reforming performed at 420°C with a catalyst, the total reforming can be achieved in 2 hours, while dehydrogenation at temperatures below 100°C can take 10-24 hours and have yields of 15-84%, depending on the catalyst used (Niermann et al. 2021). Both reactions are based on the reaction in Equation 3.4 and thus involves aqueous phase methanol. Due to the faster release time of the steam reforming process this is the process that will be used in this study, and hereafter referred to as methanol dehydrogenation.

$$CH_3OH + H_2O + heat \rightarrow H_2 + CO_2 + CO \qquad \text{Equation 3.4}$$
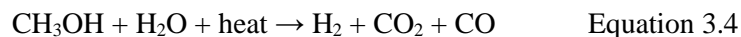
In Figure 3.7 a simplified flow sheet of the dehydrogenation process can be seen. Since the reaction is endothermic it requires heat which can be seen in the flow sheet, but electricity is also needed to run the dehydrogenation plant, which is not seen in the figure. The preferential oxidation unit is required to convert toxic CO to CO_2 and the PSA unit is required to separate hydrogen. Dehydrogenation of methanol has been estimated to TRL 9 (Niermann, Beckendorff, et al. 2019).
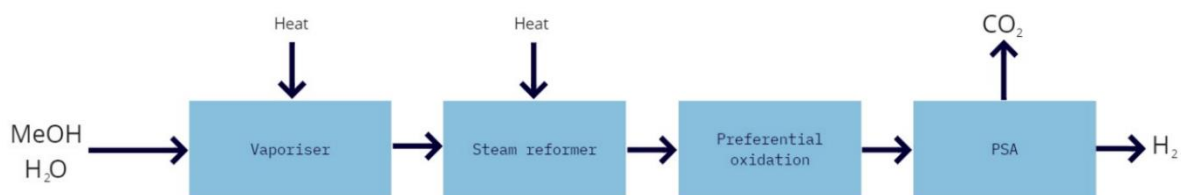

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Figure 3.7. Schematic flow chart of reconversion from MeOH.

3.2.5 LOHC (dibenzyltoluene)

Liquid organic hydrogen carriers are another way of storing and transporting hydrogen. LOHCs are liquid in their hydrogen-rich form and are (more or less) inexpensive, safe and easy to handle, thanks to having properties similar to crude oil derivatives (Niermann, Beckendorff, et al. 2019). Their purpose is to provide a measure of storage and transport that is easily realisable and with minimal boil-off and other losses. The core structure of the LOHCs remains constant during both hydrogenation and de-hydrogenation, meaning that production of new carriers for every cycle is avoided or minimised (Aakko-Saksa et al. 2018).

There are several different LOHCs that have different physical properties, costs and technological maturity. In a study by Niermann, Drünert et al. (2019) comparing the techno-economic performance of different LOHCs, toluene, dibenzyltoluene (DBT) and methanol was identified as showing large potential, benefitting from high technological maturity and low raw material prices. The potential of the carriers was also shown to depend to some degree on how process heat requirements are met (Niermann, Drünert, et al. 2019). In this study methanol is selected as a hydrogen carrier, not in the category of LOHCs but as a carrier with the possibility of direct utilisation of the molecule (omitting the reconversion step). The reason why it is not considered a LOHCs here is that the carrier molecule (CO_2) is not reused in the cases studied. Apart from this, DBT is selected to represent LOHCs while toluene is not included. The exclusion of toluene is motivated by the limited time of the thesis work and the fact that its techno-economic characteristics are similar to DBT. From here on, LOHC refers to dibenzyltoluene, if not explicitly stated otherwise. It has a liquid temperature range of -39 to 390°C and a volumetric hydrogen density of 57 kg-H_2/m^3.

Conversion – hydrogenation

Hydrogenation is the process where the LOHC is loaded with hydrogen. The carbon double bonds are saturated with hydrogen, which is an exothermic reaction, taking place at elevated pressure and temperature (Niermann, Beckendorff, et al. 2019). The reaction is exothermic and thus releases energy in the form of heat, but electricity is required for compressing hydrogen from the electrolyser output pressure to the reaction pressure (70 bar). A simplified flow sheet of the hydrogenation of DBT is shown in Figure 3.8. For DBT, the TRL of the hydrogenation process has been estimated to TRL 4 (Sekkesæter 2019) and 9 (Niermann, Beckendorff, et al. 2019), depending on the source.
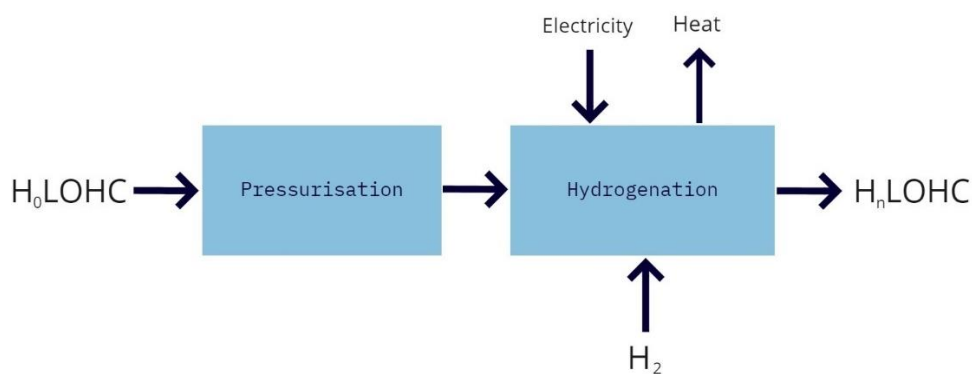

Figure 3.8. Schematic flow chart of conversion to DBT. H_0LOHC refers to the dehydrogenated form and H_nLOHC to the hydrogenated form.

Dehydrogenation is the process where hydrogen is unloaded from the LOHC. This is a catalytic endothermic reaction requiring elevated temperatures of 50-420°C, but mostly at atmospheric pressures (Niermann et al. 2021). The heat required for this process can be supplied either internally from partial burning of released hydrogen, or externally from a waste heat resource (Niermann et al. 2021). A simplified flowsheet of the dehydrogenation process is shown in Figure 3.9. The electricity demand is not indicated in this flowsheet. The dehydrogenation process for DBT has been estimated to TRL 4 (Sekkesæter 2019) and 9 (Niermann, Beckendorff, et al. 2019), depending on the source.
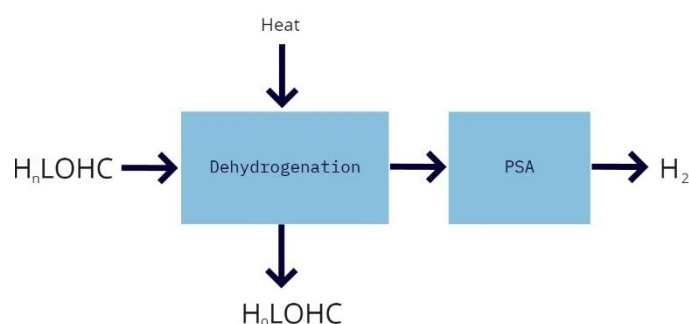

Figure 3.9. Schematic flow chart of reconversion from DBT. H_0LOHC refers to the dehydrogenated form and H_nLOHC to the hydrogenated form.

3.3 Storage

There are different ways of storing hydrogen, both as gaseous and liquid hydrogen or in the form of any of the hydrogen carriers described in the previous section. This section gives a short description of the main storage alternatives for the different forms and carriers of hydrogen considered in this thesis.

For large volumes and long storage times, gaseous hydrogen could be stored efficiently in rock or salt caverns. However, where volumes are smaller and storage times shorter or where geographic conditions does not allow for such storage, high-pressure tanks are often the standard option. This is an expensive alternative, mainly due to the low density of hydrogen even at high pressures. (DNV 2019b)

Liquid hydrogen must be stored in cryogenic tanks that are highly insulated to maintain the low temperatures. Losses due to boil-off are still unavoidable with 0.2% losses per day of storage to be expected (H21 North of England 2018). The hydrogen lost due to boil-off can be captured and reliquefied, but it means that storage of liquid hydrogen is less well suited for storage for longer times (DNV 2019b).

For ammonia, cylindrical tanks can be used to store it efficiently as a liquid at standard pressure and temperatures of -33°C or at 10 bar pressure and ambient temperatures (Giddey et al. 2017). The major issue with ammonia is its toxicity, which makes safe handling important, but as it already is an extensively traded chemical, such handling is well established (ISPT 2020). Losses due to boil-off also occur for ammonia storage but are smaller than for liquid hydrogen (Sekkesæter 2019).

Both methanol and LOHC are liquid at standard temperatures and pressures and can thus be stored easily in mineral oil tanks (Niermann et al. 2021).

3.4 Transport

Transport of hydrogen can be achieved using different modes of transport and in this section a short description of the main alternatives – studied in this thesis – is given.

3.4.1 Truck

Transport by trucks can be used for all different hydrogen carriers and are often used for smaller volumes of hydrogen transport (DNV 2019b). Both compressed and liquid hydrogen can be transported in tubes that are loaded onto trailers (IEA 2019b). The amount of compressed hydrogen that can be transported on a single trailer depend on what pressures that are allowed in the composite tanks, where a pressure of 200 bar corresponds to capacity of 720 kg-H_2 (Niermann et al. 2021). Cryogenic tanks for transport of liquid hydrogen can transport as much as 4000 kg-H_2 (IEA 2019b). Similar methods are used for truck transport of ammonia and methanol which can transport capacities of around 4000 kg-H_2, while LOHC (DBT) trucks rather have capacities around 1 300 kg-H_2 due to lower hydrogen density of dibenzyltoluene (Niermann et al. 2021). Truck transport benefits from the higher flexibility achieved through having more and smaller transport vessels, but at higher volumes other transport modes can be more cost efficient (DNV 2019b).

3.4.2 Pipelines

Another way of transporting hydrogen is by pipelines. This can be used for ammonia and gaseous hydrogen. For ammonia, pressures of 30 bar are common (at which ammonia is liquid) and for hydrogen pressures of at least 300 bar are possible (Papavinasam 2014). Today approximately 5000 km of hydrogen pipelines exist globally, mostly operated by industrial hydrogen producers to deliver hydrogen to chemical plants and refineries (IEA 2019b). Some of the main strengths of pipelines are the low operational costs and long lifetimes of 40 to 80 years (IEA 2019b). Two drawbacks are the high initial investment costs and the necessity to acquire land-usage rights for the installations (IEA 2019b).

Pipelines can be used to transport hydrogen and ammonia either using existing natural gas pipelines or by building dedicated hydrogen/ammonia pipelines. Existing natural gas pipelines offer a less expensive option, avoiding costly investments in new pipelines. They can transport hydrogen blended with natural gas or they can be repurposed to facilitate pure hydrogen transport (DNV 2019b).

Pipeline transport of liquid hydrogen, methanol and LOHC is not considered within this thesis.

3.4.3 Ship

Transport by ship can be used for most forms of hydrogen, but the TRL varies significantly between different types of hydrogen carriers. For bulk transport by sea, liquid forms are often the preferred option. LOHCs, methanol, ammonia and hydrogen can all be liquid at different conditions. The first two are liquid at ambient temperatures and have properties similar to crude oil-based liquids and can thus be easily transported with existing LPG carriers (Niermann et al. 2021). Ammonia is not liquid at ambient conditions but can be so either by pressurisation to 10 bar at ambient temperature or by cooling to -33°C at ambient pressures (ISPT 2020). Thus, ammonia too can be easily transported by ship using multi-cargo gas carriers, also used for LPG transport, and ammonia trade is well established (DNV 2019a). In contrast to the other hydrogen carriers, liquid hydrogen does not have well established options for maritime transport and its transport is complicated by the need to keep it at temperatures of around -253°C. The Japanese company Kawasaki launched the first ship for maritime transport of liquid

hydrogen in 2019, being able to transport 1250 m³ of liquid hydrogen and plans exist on building ships with capacities of 160 000 m³ (Financial Times 2019).

3.5 Offtake

The offtake is the last step of a value chain and represents the end-use of the delivered product. This step is not included in the value chains in this thesis, but a short background on what offtakes is possible is given here. This is done for hydrogen and two hydrogen carriers – ammonia and methanol.

3.5.1 Hydrogen offtake

Today, more than 50% of the hydrogen produced globally is used in the chemical industry (including production of ammonia and methanol), more than 40% is used in refineries and around 5% is used in the iron and steel sector as a reduction agent (IEA 2021). An overview of possible green hydrogen end-uses is given in Figure 3.10. It includes all possible uses of hydrogen, although some sectors are less likely to use hydrogen as decarbonisation option. For some industrial sectors – where grey hydrogen is already used extensively today or will be in the future – there is a broader consensus that hydrogen will play an important role, including the steel, ammonia, and petrochemical industries (Agora Energiewende and AFRY Management Consulting 2021; Fuel Cells and Hydrogen Joint Undertaking (FCH JU) 2019; Hydrogen Council 2021b; IEA 2019b, 2021). For sectors where other options are available (e.g. electrification), there is little consensus on what role hydrogen will play. Transport and heating are examples of such sectors, although these can be further divided into subsectors where hydrogen can play a smaller or larger role.

The demands for hydrogen purity are different for different end-uses. In some applications – especially those where hydrogen is used to power a fuel cell – regulations are very strict (DNV 2019b). This aspect is not analysed within this study.
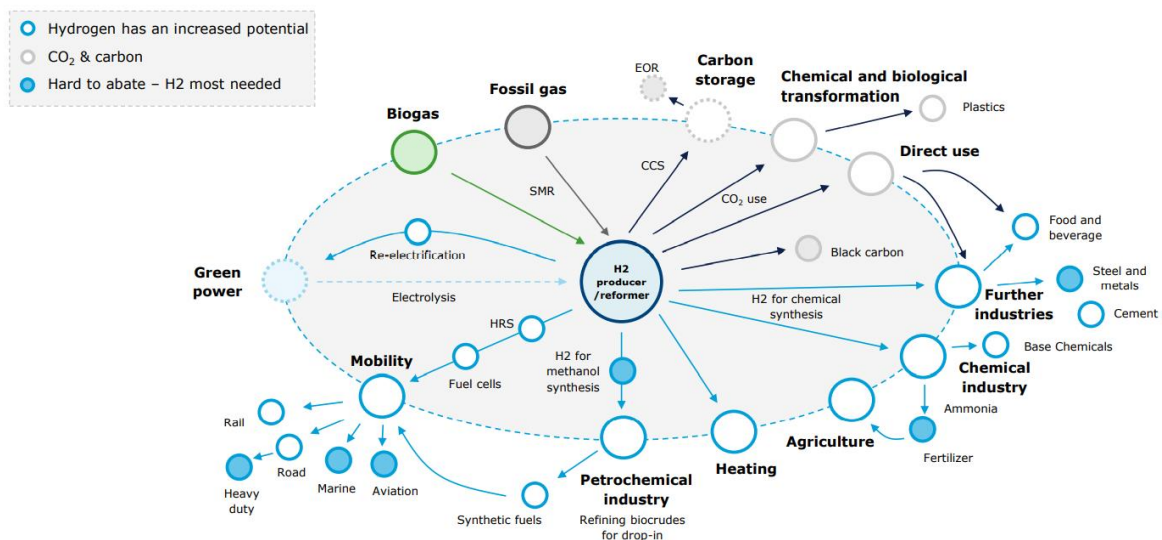

Figure 3.10. Overview of hydrogen end-uses by different sectors. The sectors where DNV see hydrogen as most needed are marked in the Figure. (With copyright permission from DNV)

3.5.2 Ammonia offtake

In the possible offtakes for hydrogen, ammonia industry is mentioned as one possible offtake. In this report ammonia is also used as a hydrogen carrier, and for this reason possibilities for direct utilisation of ammonia are briefly described here.

Today around 80% of the more than 200 Mt of ammonia produced globally is used as fertiliser (Centre for European Policy Studies 2014) and although this is mainly based on grey ammonia it is one application where green ammonia can play an important role in the future. The shipping industry is one sector where ammonia does not play a major role today, but where it is portrayed as one of the more promising decarbonisation options, especially for longer transport (World Bank 2021; Global Maritime Forum 2021; Lloyd's Register and UMAS 2020).

3.5.3 Methanol offtake

As with ammonia, the production of methanol can be seen as possible offtake, but since it is included as a hydrogen carrier in this report, the possible direct applications of methanol will also be explained briefly.

Today, around 60% of the 100 Mt methanol produced is used for producing other chemicals to the chemical industry, while around 30% is used as a fuel, either as pure methanol, for blending with gasoline or production of fuels like biodiesel, methyl tert-butyl ether and dimethyl ether (IRENA 2021). It can also be used in fuel cell electric vehicles, where the complex on-board storage of hydrogen is instead replaced by methanol storage and on-board reformation. The use of methanol as a fuel is also growing in the shipping sector, where 20 large ships are already in operation or on order (IRENA 2021) and where several pilots and demonstration projects are underway (Fahnestock and Bingham 2021). The increasing use of methanol in this sector is both a way to comply with emission limits of emission control areas, proliferating around the world, but also a measure to meet the decarbonisations goals set up by the International Maritime Organisation (IRENA 2021).

The demand for methanol is expected to grow, mainly driven my olefin production in China (IRENA 2021), but as methanol is also portrayed as a promising fuel for the shipping sector (Global Maritime Forum 2021; Lloyd's Register and UMAS 2020), among others, where competition from alternative fuels exist, the level and sector distribution of increased demand is uncertain.

4 Method

4.1 A business case scenario builder

The main calculations done within the thesis are made using a business case scenario builder, developed by DNV as a proprietary model for assessing offshore wind and Power-to-Hydrogen projects. It was further developed within the thesis to facilitate the analysis of value chains downstream of the electrolyser. In this section the model is explained and then the contribution of the thesis work is clarified.

4.1.1 A business case scenario builder

The model provided by DNV for the thesis work is an Excel model used to compare different business cases for offshore wind power and P2H in terms of capital budgeting measures such as net present value (NPV) and levelised cost of electricity (LCOE). It combines asset data (CAPEX, OPEX, lifetime, efficiency etc.), power production curves, market data (prices of electricity and hydrogen) and business case settings (e.g. electrolyser location and operation mode) to calculate the measures. A graphical description of the model can be seen in Figure 4.1.
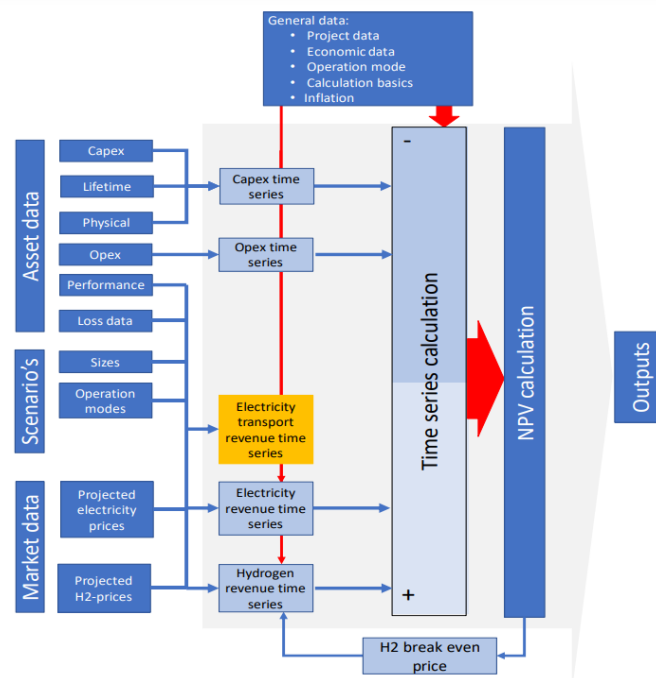
Figure 4.1. Schematic description of the business case scenario builder model used and developed in the thesis. (With copyright permission from DNV)

LCOE and LCOH

For the scope of the thesis, only LCOH (based on LCOE) and total costs are used as measures. LCOE is defined by IRENA as "*the price for electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate*" (2012). It is an economic measure used to compare lifetime costs of generating electricity across various technologies or business cases. The levelised cost of hydrogen (LCOH) is based on the LCOE method but applied for the production of hydrogen, which can be presented both as cost per unit energy and mass

(Viktorsson et al. 2017). The equation defined by IRENA (2012) for calculating LCOE that can also be used for LCOH is:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \quad \text{Equation 4.1}$$

Where:
$LCOE$ (or $LCOH$) = average lifetime levelised cost of electricity (or hydrogen);
I_t = investment expenditures in the year t;
M_t = operations and maintenance expenditures in the year t;
F_t = fuel expenditures in the year t;
E_t (or H_t) = electricity (or hydrogen) generation in the year t;
r = discount rate; and
n = economic lifetime of system.

When LCOE and LCOH is to be determined there are some parts of the model that might seem superfluous. Since the basic formula of LCOE is to divide costs with energy, it is in principle only the time series for costs (CAPEX, OPEX, variable OPEX, repair) and energy (flows of electricity/hydrogen) that are required. The projected prices of electricity and hydrogen are used in NPV calculations to calculate revenues. However, there are three parts of the model that make the power prices forecast necessary also for the LCOE calculation. One part is the operation mode of the electrolyser, which can be set to run on operation modes that produce hydrogen from the wind power only when the electricity price falls below a certain level. A second part is also related to the electrolyser operation mode and is relevant for business cases where it is set to complement the electricity from the offshore windfarm (OSWF) with electricity from the grid. It can then be set to use grid electricity only at times when the electricity price is below a certain level. The third aspect making the electricity price necessary for the LCOE calculations is because all electricity consumption downstream of the electrolyser is implemented as variable OPEX (instead of as throughput efficiency), where the price of electricity is set as the mean value of all hourly prices in the power price forecast. These assumptions are further described in the below section Data collection and assumptions.

4.1.2 Thesis contribution to model

The thesis work has used the DNV model as a foundation but developed it further to facilitate necessary analysis. The main contribution has consisted of adding modules for value chain steps downstream of the electrolyser, including conversion to hydrogen carriers, buffer storage, transport and reconversion back to gaseous hydrogen. For the modules added, the cost part of the model was also extended by adding variable OPEX to the already existing CAPEX, fixed OPEX and repair costs. This variable OPEX is used for costs where variable costs are considered too significant for being simplified using a fixed OPEX (% of CAPEX). This includes costs for use of electricity and feedstock (CO_2 and DBT) for the conversion and reconversion units.

4.2 Definition of value chains

In this section the process for defining value chains is first described and motivated before an overview of the value chains is presented.

4.2.1 Geographical setting

Value chains are set up for two different geographical cases, visualised in Figure 4.2. Both have their base in power production from the licensing area Sørlige Nordsjø II and hydrogen production onshore in Norway at the coast close to this site (approximately 200 km away). The hydrogen is then transported to either of the two end destinations included in this study - Porsgrunn or Rotterdam. Porsgrunn is chosen to represent the Norwegian market as this is an industrial cluster located approximately 200 km from the intended hydrogen production site. Rotterdam is chosen to represent the European market, located close to many of the industrial clusters of Western Europe, approximately 500 km (across the North Sea) from the intended hydrogen production site.
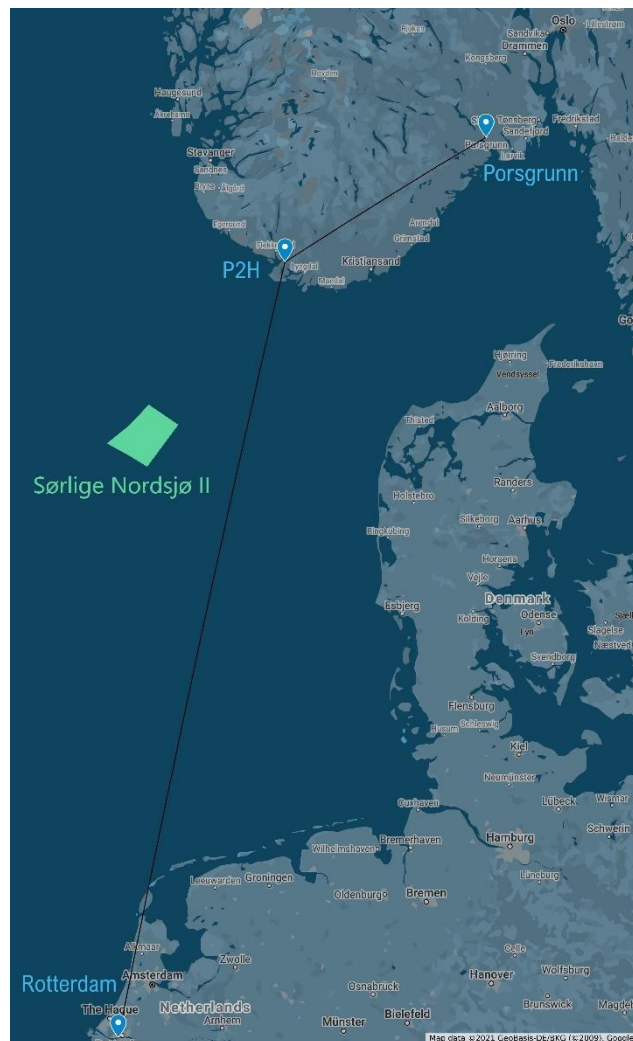
Figure 4.2. Map illustrating the geographical context including the OSWF ("Sørlige Nordsjø II"), electrolyser location ("P2H"), and offtake locations ("Porsgrunn" and "Rotterdam").

4.2.2   Value chain configurations

For these two geographical cases a set of relevant value chains are set up and studied. To be able to focus the analysis on the aspects most relevant for the purpose of the study there are some parts of the value chains that are kept constant across all value chains. The value chains are all set up as variations of the general value chain shown in Figure 4.3. The variations are created by looking at 1) different hydrogen carriers in different forms and 2) different modes of transport.
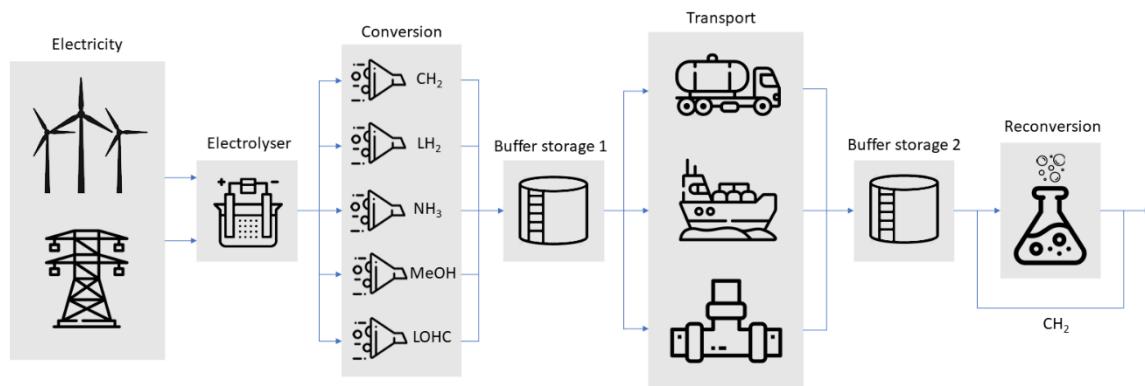
Figure 4.3. Value chain configuration options. CH_2 = compressed hydrogen, LH_2 = liquid hydrogen, NH_3 = ammonia, MeOH = methanol and LOHC = liquid organic hydrogen carrier.

The different hydrogen carriers and forms include compressed gaseous hydrogen (CH_2), liquid hydrogen (LH_2), ammonia (NH_3), methanol (MeOH) and the liquid organic hydrogen carrier (LOHC) dibenzyltoluene. These can then be transported by either truck, pipeline or tanker ship. Pipelines are only considered for transporting CH_2 and NH_3 and truck transport is only considered for the Porsgrunn case. Ship is not considered for transporting CH_2. In total this gives 17 possible value chains (11 for the Porsgrunn case and 6 for the Rotterdam case).

Pipeline transport of LH_2 is not technically feasible and therefore not included. It is however technically feasible to use pipeline transport for MeOH and LOHC, but this is not considered due to time limitations.

4.2.3 Value chain overview

An overview of the different value chains involved in the study is presented Table 4.1. Value chains with CH_2 are not included since this is considered to inefficient, and value chains with truck are not included to Rotterdam since the land-based route is too long.

Table 4.1. Overview of value chains included in the analysis.

Value chain name	OSWF	Electrolyser	Hydrogen carrier	Transport mode	Destination
"Porsgrunn CH_2 truck"	1200 MW	345 MW alkaline	CH_2	Truck	Porsgrunn
"Porsgrunn LH_2 truck"	⫽	⫽	LH_2	Truck	Porsgrunn
"Porsgrunn NH_3 truck"	⫽	⫽	NH_3	Truck	Porsgrunn
"Porsgrunn MeOH truck"	⫽	⫽	MeOH	Truck	Porsgrunn
"Porsgrunn LOHC truck"	⫽	⫽	LOHC	Truck	Porsgrunn
"Porsgrunn LH_2 ship"	⫽	⫽	LH_2	Ship	Porsgrunn
"Porsgrunn NH_3 ship"	⫽	⫽	NH_3	Ship	Porsgrunn
"Porsgrunn MeOH ship"	⫽	⫽	MeOH	Ship	Porsgrunn
"Porsgrunn LOHC ship"	⫽	⫽	LOHC	Ship	Porsgrunn
"Porsgrunn CH_2 pipeline"	⫽	⫽	CH_2	Pipeline	Porsgrunn
"Porsgrunn NH_3 pipeline"	⫽	⫽	NH_3	Pipeline	Porsgrunn
"Rotterdam LH_2 ship"	⫽	⫽	LH_2	Ship	Rotterdam
"Rotterdam NH_3 ship"	⫽	⫽	NH_3	Ship	Rotterdam
"Rotterdam MeOH ship"	⫽	⫽	MeOH	Ship	Rotterdam
"Rotterdam LOHC ship"	⫽	⫽	LOHC	Ship	Rotterdam
"Rotterdam CH_2 pipeline"	⫽	⫽	CH_2	Pipeline	Rotterdam
"Rotterdam NH_3 pipeline"	⫽	⫽	NH_3	Pipeline	Rotterdam

4.3 Data collection and assumptions

Apart from developing the model and configuring value chains, an important part of the thesis has consisted of collecting and making assumptions about data for the different parts of the value chains. Most of the data collection has been performed by searching through literature, covering similar studies of value chain analysis, studies of specific plant types and reports from international energy organisations. Data for the more upstream parts of the value chains (OSWF to electrolyser) was already collected and added in the model by DNV. The data that is of most relevance for the study is presented in tables in Appendix. Exchange rates that have been used for currency conversion in the data collection are presented in Table A6 in the Appendix. In the following sections, relevant assumptions for all parts of the value chains are explained.

4.3.1 Frame assumptions

All value chains include a 1200 MW bottom fixed OSWF located at the license area Sørlige Nordsjø II, located 190 km from the coast of southwestern Norway. It is connected to a 345 MW alkaline electrolyser and to the electricity market in Norwegian electricity bidding zone NO2. An overview of what technology options are used for each step is provided in Appendix Table A1. All value chains end in either Porsgrunn or Rotterdam as compressed hydrogen at 40 bar and 20°C. The pressure of 40 bar is assumed despite the penalty it implies to the value chain including hydrogen compression to 350 bar and is motivated by the fact that a higher pressure might not be necessary for many applications. No cost changes in costs are assumed for any parts except for the electrolyser CAPEX.

4.3.2 OSWF and electrical supply

Assumed economic and technical parameters of the OSWF, substations and power cables are summarised in Appendix Table A2. These are kept constant for all value chains to focus the analysis on the parts further downstream. The cost of electricity that comes from this part of the system corresponds to 49 €/MWh.

4.3.3 Hydrogen production

Assumed economic and technical parameters of the electrolyser are summarised in Table A3 in Appendix. All value chains are assumed to be based on an alkaline electrolyser, as the grid connection makes electrolyser flexibility less important. Since the electrolyser is one of the most important cost drivers of a P2H system it is important that reasonable numbers and assumptions are used. In particular, CAPEX of the electrolyser has a big effect on the levelised costs and – as mentioned in section 5.3 – expected cost reductions make it uncertain what the CAPEX will be in 2030, which is the case year in this study. The lower CAPEX assumed in the calculations (96 €/kW for a 100 MW alkaline system) corresponds to a learning rate of 30% and an electrolyser deployment of 65 GW by 2030[1]. These are optimistic assumptions, especially as the learning rate is at the higher range of expected levels[2]. In the calculations this estimated value of CAPEX is adjusted to account for economies of scale according to Equation 4.2 below, assuming different scale factors for the main components (weighted according to their share of total cost) stack (30%), electronics (20%) and balance of plant (50%). The equation also adds 100% of CAPEX (by multiplying with 2) to account for transport and installation.

$$CAPEX = CAPEX_{ref} \cdot \left(0.3 \cdot \left(\frac{size}{100}\right)^{0.95} + 0.2 \cdot \left(\frac{size}{100}\right)^{0.8} + 0.5 \cdot \left(\frac{size}{100}\right)^{0.7} \right) \cdot 2 \qquad \text{Equation 4.2}$$

The operation mode of the electrolyser decides how the electricity from the OSWF is divided between the electrolyser and sale at the power market. As the focus of the analysis is on the elements downstream of the electrolyser, a simple "proportional" operation mode is assumed, where a share of the produced electricity corresponding to the electrolyser capacity share of the OSWF capacity is used to power the electrolyser. This share is 30% in all studied value chains. Apart from the electricity supplied to the electrolyser by the OSWF it is also assumed that grid power is used to complement the wind power. This complement is used for the idle electrolyser capacity at times when the electrolyser's proportion of wind power is too small to run at full capacity (all hours where OSWF runs below 100% capacity). This grid electricity is paid for according to simulated market prices and is assumed to be used if the

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[1] Assuming a 2019 CAPEX of 837 €/kW and a deployment from 1 GW in 2019 to 65 GW in 2030, corresponding to the combined capacity goals set up by EU and Chile.
[2] Current expectations range from 11-12% but might be too conservative, according to Hydrogen Council, since development of batteries, solar PV and onshore wind saw learning rates of 20-40% (2021b).

market prices are below 20 €/MWh in order to avoid producing hydrogen at too high prices. The mean price of the grid-supplied electricity is 12 €/MWh (when assuming the 20 €/MWh threshold).

4.3.4   Conversion and reconversion

Assumed economic and technical parameters of the conversion and reconversion modules are summarised in Table A4 in the Appendix. The CAPEX of units is estimated based on reference values from literature. Since CAPEX for chemical plants are generally dependent on size a scaling formula has been used to scale from the reference plants to the case plants. To account for costs changing over time, the Chemical Engineering Cost Plant Index (CEPCI) is used. As it is an index based on historic costs, and in the calculations, costs are only updated to the latest existing year of the index (2019) instead of to the reference year of the study (2030). Another adjustment that is sometimes used for estimating plant CAPEX is BNP-adjustment, used to account for differences in costs between different countries. However, since several of the reference values used in this study do not specify country, this adjustment is neglected for all units to make the estimations more consistent. The equation used for estimating the plant CAPEX is displayed in Equation 4.3 below, where S is capacity, SF is scale factor and CEPCI is the index number from the Chemical Engineering Plant Cost Index.

$$CAPEX_{case} = CAPEX_{ref} \cdot \left(\frac{S_{case}}{S_{ref}}\right)^{SF} \cdot \frac{CEPCI_{case}}{CEPCI_{ref}} \qquad \text{Equation 4.3}$$

OPEX has been divided into a fixed and variable part for these modules since some of them have significant variable costs. The fixed OPEX is implemented as a % of CAPEX while the variable OPEX is implemented as cost for feedstock (for MeOH and LOHC) and electricity per throughput of hydrogen.

The feedstock cost for LOHC is for replenishing the carrier (DBT) since 0.1 wt.% of it is assumed to be lost for each cycle. For MeOH the feedstock cost is for CO_2, which is not assumed to be recycled and must thus be fully replenished for each cycle. The cost of CO_2 depends on the source and costs are uncertain since the technology is immature. The highest costs in the span are for direct air capture, while a smaller cost is assumed if the CO_2 can be supplied from a concentrated source, such as a combined heat and power plant (IRENA 2021).

The electricity for conversion and reconversion is assumed to be supplied using grid electricity. To ensure a continuous throughput of hydrogen through the value chain this power supply is assumed to be independent of power prices. The cost for electricity is instead calculated as the mean value of all simulated hours in the power price forecast, which is 41.3 €/MWh. This is significantly higher than the mean price for the grid electricity (assuming threshold) used by the electrolyser (12 €/MWh), but is motivated by the need for a continuous throughput and the negligible electricity requirements for the conversion and reconversion processes (~8.8 kWh/kg-H_2 for the most electricity demanding value chain) compared with electrolysis (~44 kWh/kg-H_2).

While feedstock and electricity requirements are implemented as variable OPEX, heat requirement for conversion/reconversion is treated differently. Heat for these processes could be supplied from different sources, such as using waste heat or by burning natural gas or hydrogen. Using waste heat can be a cost and energy efficient way, but it requires that the temperature of the waste heat source be sufficient to meet the demands of the processes. While this alternative is promising it is not considered in the thesis, as it would require more detailed analysis of heat requirements and knowledge about nearby waste heat

sources. Instead, heat is assumed to be supplied by burning some of the produced hydrogen, as this has considerably less climate impact than burning natural gas.

4.3.5 Transport

Assumed economic and technical parameters of the transport module are summarised in Table A5 (ship and truck) and Table A7 (pipeline) in Appendix. The assumptions for truck and ship transport are based on similar principles, while those for pipeline transport differ slightly.

For both truck and ship transport, CAPEX is based on the number of transport vessels that is assumed for covering the design throughput of the conversion units. The number of vessels necessary is calculated based on assumptions of utilisation (hours of the year), payload capacity and round-trip time (incl. loading/unloading). For the production volumes studied the size of transport ships mean that only a small share of a ship's cargo capacity is necessary for covering the hydrogen throughput. It is assumed that these value chains cover the whole CAPEX for these ships although they are only utilising a share of them. This implies an overestimation of this value. OPEX for truck and ship transport is implemented only as a fixed OPEX (% of CAPEX). The reason why no variable OPEX is included to account for fuel costs is since it is assumed that the transport vessels will not adjust travel patterns according to fluctuations in hydrogen production. While this assumption might not be fully realistic, it is considered a sufficient simplification since fluctuations are relatively small and since implementation of such a variable cost would require more detailed implementation of transport routes and behaviour.

For the LOHC value chains the CAPEX also includes the cost for the LOHC material (DBT). The amount of DBT is calculated by assuming that all transport vessels (trucks and ship) are constantly filled with DBT but leaving space for the extra weight added from hydrogenation. This is because the vessels need to transport the dehydrogenated carrier back to the hydrogen production site for hydrogenation. For ship transport, the amount of DBT is based on the share of the ship that is assumed to be utilised, based on the calculations described in the above paragraph.

CAPEX of the pipelines is calculated using a calculation model developed by DNV for hydrogen pipeline transport, which assumes that for a certain capacity, the diameter and cost-per-km increase with transport distance, with different numbers for 100, 250 and 500 km. The DNV calculation model for hydrogen pipeline transport has been used also for NH_3 transport, including an adjustment to account for the higher volumetric hydrogen density in ammonia. The adjustment is displayed in Equation 4.4 and involves multiplication with an adjustment factor of 0.644 derived from assumptions used by IEA (2019a). For both CH_2 and NH_3, 60% is added to CAPEX to represent offshore pipelines.

$$CAPEX_{NH_3,DNV\ model} = 0.644 \cdot CAPEX_{H_2,DNV\ model} \qquad \text{Equation 4.4}$$

4.3.6 Buffer storage

Assumed economic and technical parameters of the storage module are summarised in Table A8 in Appendix. Short-term buffer storage is necessary to account for the temporal gap between conversion/reconversion and collection/delivery by the transport vessels (truck or ship). The capacity (expressed as hours of design production for conversion/reconversion units) of these storage modules is assumed to be dependent on the frequency of collection/delivery for the transport mode and is calculated using Equation 4.5.

$$Buffer\ storage\ capacity = \frac{Roundtrip\ time}{No.of\ vessels} \cdot Extra\ buffer\ factor \quad \text{Equation 4.5}$$

For a value chain where only one vessel is necessary (all value chains with ship transport), the buffer time is thus equal to the roundtrip time multiplied with the extra buffer factor. The extra buffer factor is assumed to be 10[1] and is included to make the system more resilient to disturbances in the transport chain. The CAPEX of the storage modules is assumed to be independent of scale (scaling factor = 1) and only fixed OPEX is included. For the value chains with pipeline transport the line packing ability of the pipelines is assumed to facilitate necessary buffering, and thus no separate buffer storage is included. Further, for the CH_2-value chains with truck transport no reconversion is needed and thus no buffer storage is necessary after transportation, assuming a continuous offtake at the point of delivery.

For the LOHC value chains, the cost for storage is dominated by the cost of the LOHC material (dibenzyltoluene), as the cost for mineral oil tanks are negligible compared to this. The cost per capacity is thus decided as the raw material cost for dibenzyltoluene. For MeOH, the carrier molecule (CO_2) is assumed to produced anew for each cycle and not recirculated. This means that the raw material cost for MeOH is instead implemented through the conversion module.

4.4 Investigation of uncertainties/sensitivities

An important part of the calculations is to study what effect uncertainties and sensitivities have on the results. There are several different uncertainties that are relevant to consider. Since the study investigates business cases nine years into the future (2030) there are uncertainties regarding technology development that should be tested. The sensitivity of results to longer buffer storage capacity for truck value chains is also investigated. Finally, the sensitivity of results to different discount rates is investigated.

4.4.1 Technology development

There are many different technology aspects of the value chains that might develop until 2030, but to keep the investigation within reasonable limits a selection of the most relevant ones is made. All are investigated by setting up a high and low cost/performance level and calculating the results for both these levels.

Electrolysers

The development of electrolysers is one such development, a massive increase in installed capacity is expected and is likely to come with improvements in both costs and performance. For this reason, a range of both future CAPEX and efficiency is investigated, as these are the aspects where change might be the largest and have the largest effect on the LCOH. For CAPEX especially, a significant improvement is assumed compared to today's levels.

Processing units

Another aspect of technology uncertainty concerns the processing units involved when converting hydrogen to and from its different hydrogen carriers. As some of the processes have not been deployed at significant scale to date, there are uncertainties in how costs will look when they are. These uncertainties are clear when going through literature for data collection, as large spans can be found for

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[1] Factor was assumed to be large enough to yield capacities for the truck transport that was not at least 20 minutes, since lower capacities was deemed implausible.

several of the technologies. The processing units are investigated for uncertainty in CAPEX, where spans are based on those found in literature, but assuming that no cost reductions are made from now until 2030.

CO$_2$ feedstock costs

For the value chains that are based on methanol, CO$_2$ is required as feedstock. This is assumed to be provided by direct air capture, a technology that is currently associated with large costs and where significant cost reductions are expected (IRENA 2021). The extent of these cost improvements is uncertain, and for this reason a span is investigated.

In Table A9 in Appendix the spans used in the study are presented. For the main results of the study, the low level has been used for electrolyser CAPEX, processing unit CAPEX and CO$_2$ feedstock, while the high level has been used for efficiency. The effect of going to the other ends of the spans are then studied one by one. For some units, one value has been found in literature, and thus no span exists.

4.4.2   Buffer storage

The buffer storage is not related to any uncertainties of relevance with regards to technology development. Rather, the reason to why it is included in the sensitivity studies is related to the sizing. The method used in the thesis to determine the necessary storage capacity yields capacities that are small – especially for the truck value chains – and that might be smaller than what is plausible. For this reason, the uncertainty investigation involves a calculation of similar nature to those for uncertainties in technology development, but where the high value is instead chosen as a storage capacity that is higher and considered more plausible. This is done for the truck value chains but not the ship value chains, as the buffer storage capacities for those are considered more plausible. For simplicity, the high value of capacity (expressed in tonnes of hydrogen) is set to be the same for all five carriers – five days of production – even though this implies a penalty for CH$_2$ and MeOH, that have smaller capacities in the original calculations (CH$_2$ due to having more trucks and MeOH due to having more H$_2$ losses in the conversion).

4.4.3   Discount rate

The discount rate determines how costs taking place at different times are compared to each other and is thus an important part of capital budgeting. A high discount rate means that costs taking place far into the future are weighted lower than those taking place at the reference year, giving upfront investment costs a larger importance. The opposite is true for low discount rates. What discount rate that should be used for an investment calculation depends on different factors, such as the cost of capital and the risk level of the investment, and it is difficult to say what is the "correct" rate. In the main calculations of this thesis a discount rate of 6% is used, but to see the effect of using higher discount rates the value chain performances are also calculated using a discount rate of 12 %, based on a study of discount rates used by US companies' (Poterba and Summers 1995).

5 Results & analysis

The results and analysis of the study are divided into four different parts. First the overall value chain performances are presented, including LCOH for all considered value chains where the cost contribution of the different value chain steps are visualised as well as the division of cost between CAPEX, OPEX and repair costs. The effect on these results of different uncertainties is then presented in the second part, including technology uncertainties and sensitivities to assumptions on discount rate and buffer storage. The third part presents a literature comparison, comparing the results to those of similar studies. In the last part the calculations regarding direct utilisation of NH_3 and MeOH are presented. The first three parts are mainly related to the first and second research question, while the last one relates to the third research question.

5.1 Value chain performances

An overview of the value chain performances – using lower cost levels and electrolyser efficiency – are visualised in Figure 5.1.

These results show that for Porsgrunn, the two value chains based on CH_2 (truck and pipeline) have the lowest LCOH. Both these two value chains have LCOHs around 3 €/kg-H_2, while the other ones are around 4 €/kg-H_2, and up to more than 5 €/kg-H_2. For Rotterdam "*CH_2 pipeline*" is clearly the value chain with the lowest LCOH (4 €/kg-H_2), while the other ones range from 4.7 to 5.7 €/kg-H_2.

An important assumption to mention, relating to the pipeline value chains to Porsgrunn, is that the pipeline is assumed to be constructed in a straight line. No consideration is taken to hilly terrain, which is the geographical reality for the area between the electrolyser site and Porsgrunn. This implies an underestimation of costs for the "*Porsgrunn CH_2 pipeline*" and "*Porsgrunn NH_3 pipeline*" value chains.

One observation from the graph is that the contribution of the power production ("LCOE" in the figure) and electrolyser to the total LCOH is different for the different value chains, although the same capacity of these two elements are used for all value chains. The reason is that the measure used is LCOH, which means that although the absolute cost for these elements is the same across all value chains, different value chain outputs of hydrogen (due to different levels of loss along the chains) means that the costs per kg H_2 varies. Thus, the height of the lowest bar gives an indication of the losses for each value chain, where the ones with a higher LCOE-bar have higher value chain losses.

Following the above argument, the graph infers that hydrogen losses have a significant impact on the results. The MeOH and LOHC value chains can attribute a large share of their LCOHs to the electricity production (LCOE) and electrolyser, which are significantly higher than for the other carriers due to the high losses associated with these carriers.

Another observation is that the cost for buffer storage is negligible for all truck value chains. This is not surprising considering that the buffer storage capacities for these value chains are very low, ranging from 2.9 to 17.9 t-H_2 (corresponding to 0.4-2.6 hours of production). The effect of assuming a larger buffer storage for truck value chains is investigated under Uncertainties and sensitivities.

Figure 5.2 illustrates the total levelised costs for the same value chains but broken down into different cost types. It illustrates that CAPEX is the dominating cost type for all value chains, and that it does not

differ significantly in level between the different value chains. This means that, for the different value chains considered, a similar level of upfront capital is necessary for all value chains.

Figure 5.1. Value chain performances for lower cost levels and higher electrolyser efficiency, broken down into the different value chain steps, expressed as LCOH. "LCOE" refers to levelised cost of electricity, including the OSWF, substations and cables.
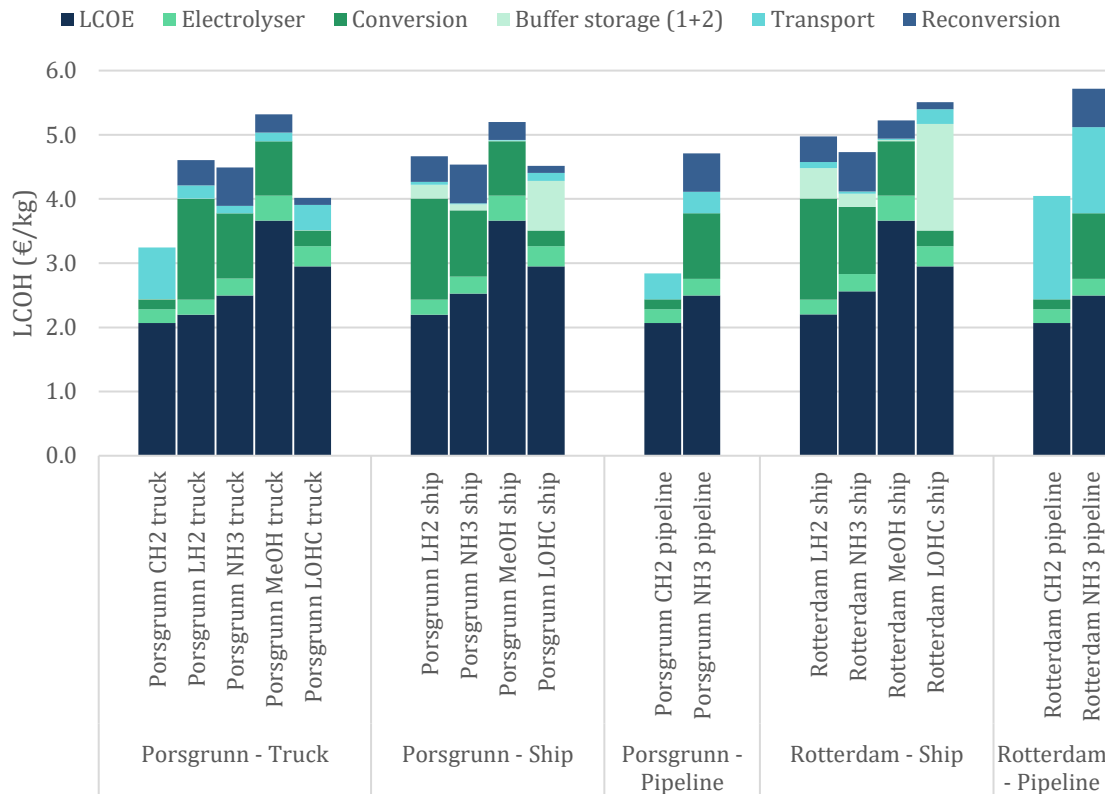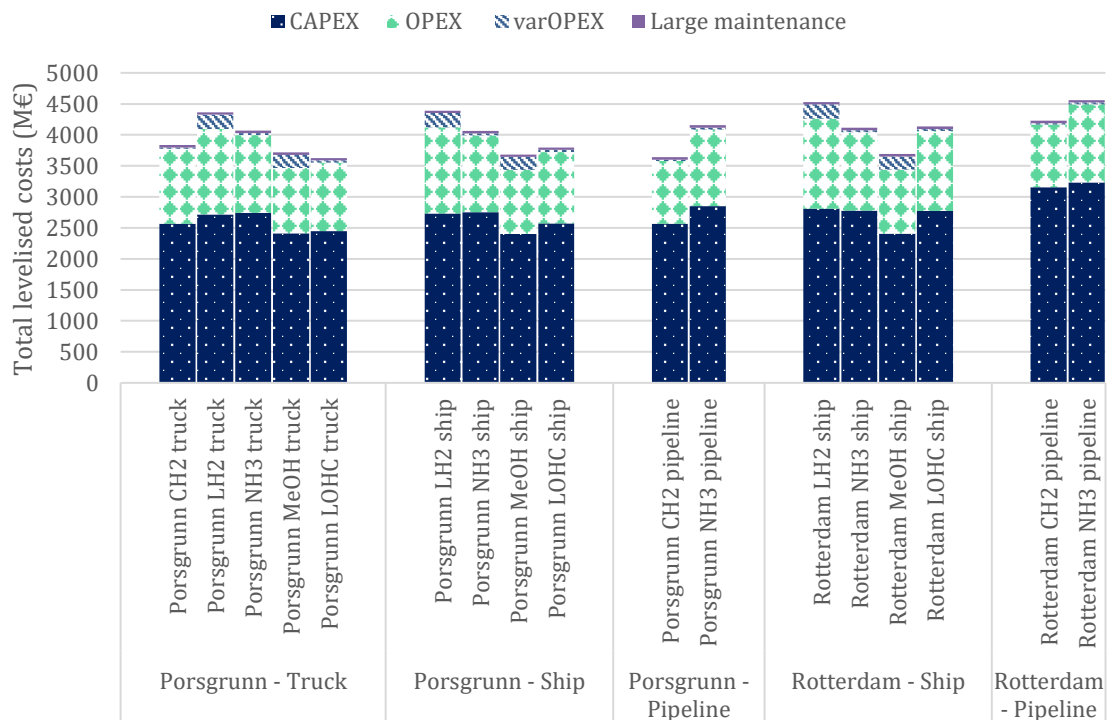

Figure 5.2. Value chain performances for lower cost levels and higher electrolyser efficiency, broken down into costs for CAPEX, OPEX, variable OPEX and large maintenance, expressed as total levelised costs.

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5.2 Uncertainties and sensitivities

In this section the result of the testing for uncertainties and sensitivities are presented. The effects of uncertainties for technology are first presented one by one, before the total effect is summarised in one graph. The sensitivity of the results for a higher discount rate and for the assumption regarding buffer storage for truck value chains are then presented separately.

5.2.1 Uncertainties in technology

The effects of uncertainties in electrolyser CAPEX and efficiency are displayed in Figure 5.3. As the bars indicate, the effect on value chain LCOHs comes mainly from the CAPEX uncertainty, but there is also a marginal contribution from the uncertainty in efficiency. Note however that the effects are similar for all value chains and thus have no impact on which value chain is more promising, but rather on the overall competitiveness of these value chains compared to alternatives like grey or blue hydrogen.
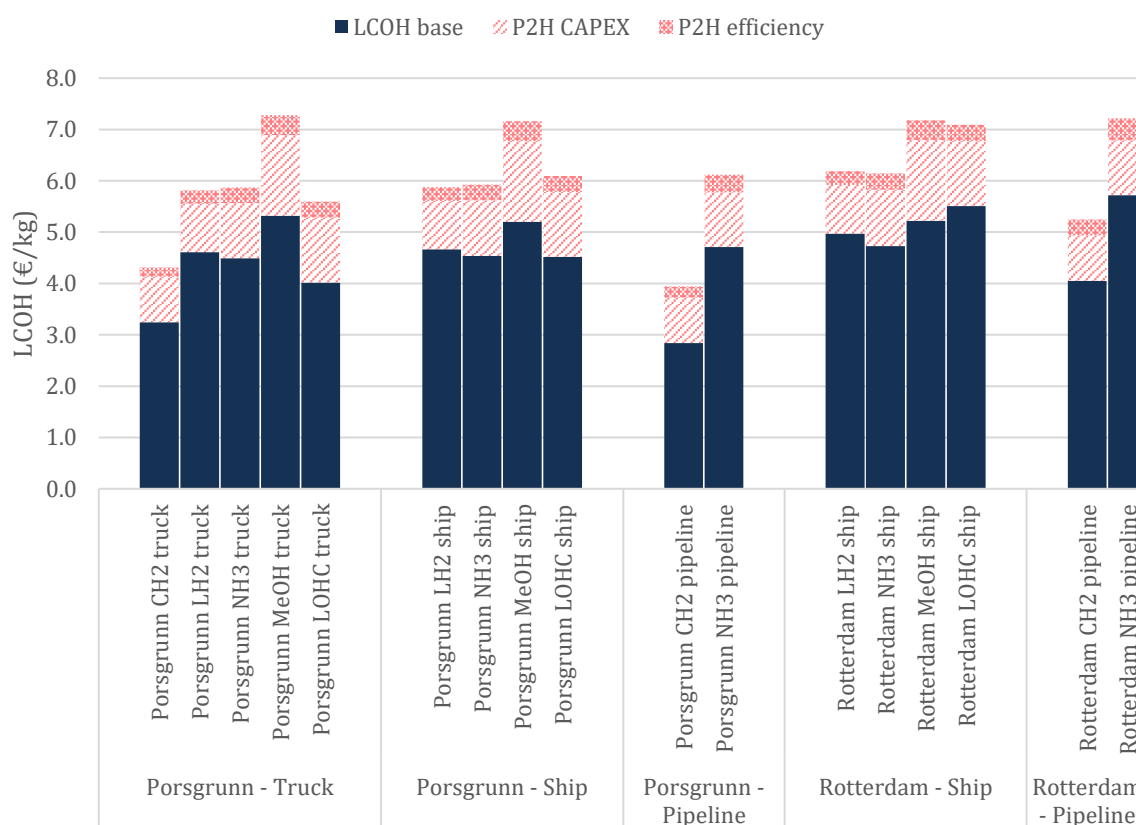

Figure 5.3. Value chain performances including uncertainty added from electrolyser costs ("P2H CAPEX") and efficiency ("P2H efficiency").

In Figure 5.4, the effect of uncertainty in CAPEX for the different conversion and reconversion units is visualised. What the results indicate is the large difference in uncertainty between different hydrogen carriers. While the uncertainty increases the LCOH with more than 50% for LH_2 value chains, the effect is marginal for NH_3 and LOHC value chains and non-existent for the CH_2 value chains.

These results are reflected in the TRL of these processes, where processing of CH_2 has the highest maturity with TRL 9 for both conversion and reconversion. NH_3 has TRL 9 and 4 for conversion and reconversion respectively, MeOH has TRL 9 for conversion and TRL 3 or 9 (depending on high or low temp. reforming) for reconversion and LOHC has TRL 9 for conversion and TRL 4 for reconversion. LH_2 processing technology has a lower maturity of TRL 3 and 4 for conversion and reconversion.

An important feature of the uncertainties in processing CAPEX is that these only add costs to the value chains which already have highest costs. No uncertainties in CAPEX for the CH_2 compression was considered as no significant spans was found in the data collection and since it is considered a more mature technology. Thus, the results from these results support rather than contradict the indication from the base results, that the CH_2 value chains are the most promising ones.
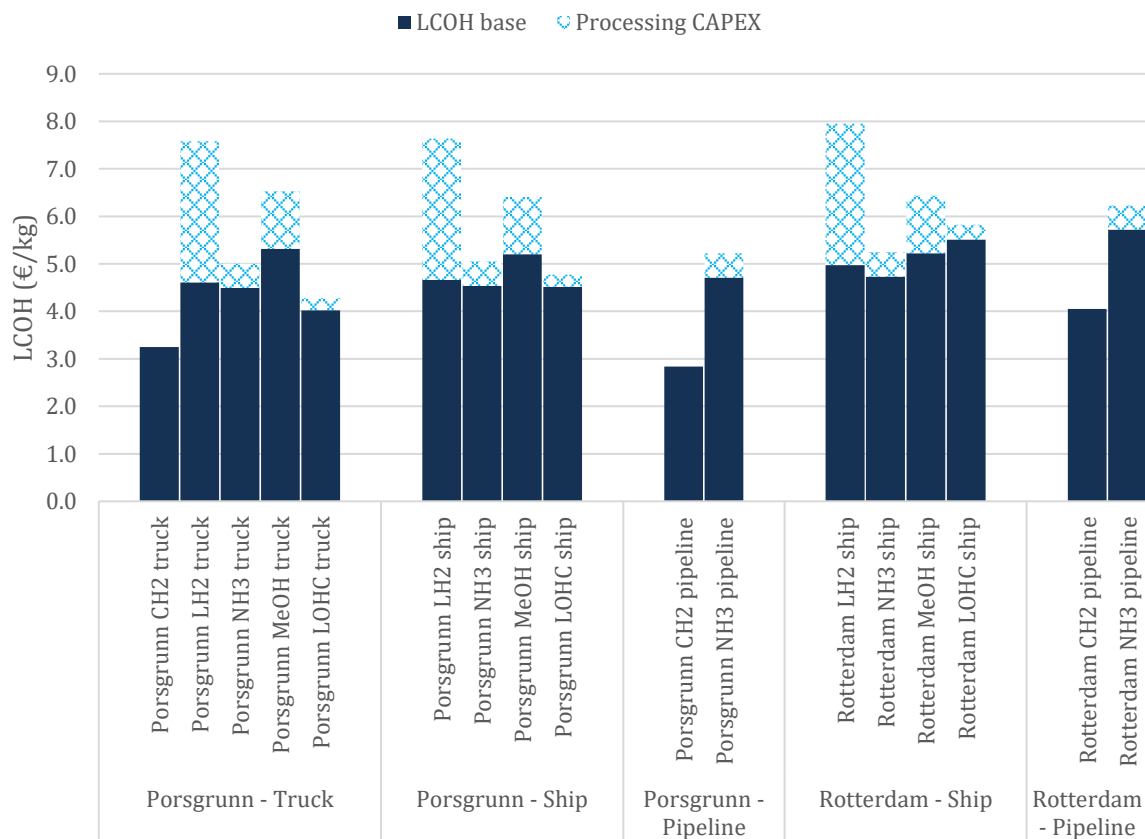
Figure 5.4. Value chain performances including uncertainty added from costs for conversion and reconversions units ("Processing CAPEX").

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The effect on LCOH from the uncertainty in future costs for direct air capture of CO_2 is displayed in Figure 5.5. As can be expected, this uncertainty only affects the performance of the MeOH value chains. The effect is significant for all these value chains, stressing the importance of decreasing costs for this technology, considering that both the high and low values assume significant reductions from today's costs.

Figure 5.5. Value chain performances including uncertainty added from the feedstock cost for CO_2 ("CO2 price").

If all uncertainties are added together, a more complete picture of ranges for value chain performances can be achieved, visualised in Figure 5.6.

These results support the observations from the base results: the CH_2 value chains are least expensive for both geographic cases, especially the pipeline value chains, but also the truck value chain for Porsgrunn. The LH_2 and MeOH value chains are expensive compared to those with CH_2 regardless of uncertainties, however, the difference is significantly larger when uncertainties are considered.
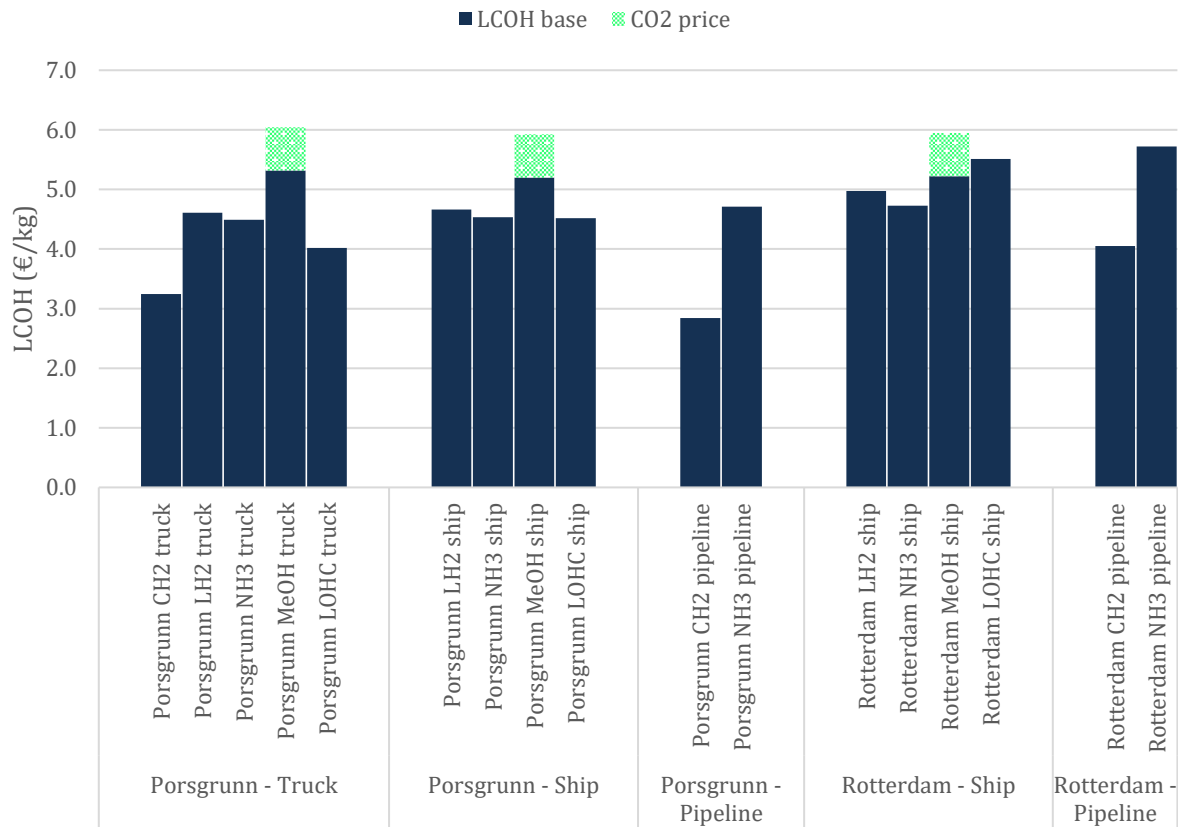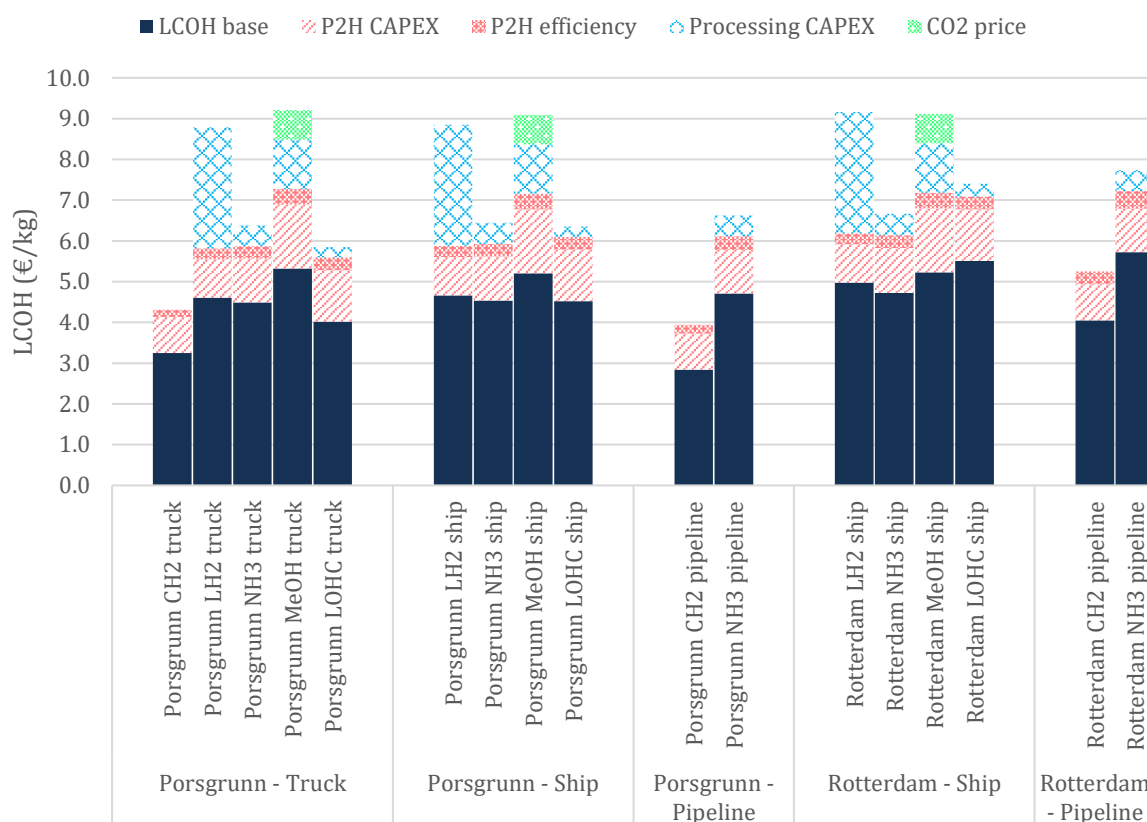

Figure 5.6. Value chain performances including uncertainty added from the four different aspects included in the study.

5.2.2   Sensitivity for higher buffer storage capacity

Since the calculations of buffer storage capacity for truck value chains yield a value that is remarkably low, the case where a higher capacity would be assumed is analysed here. In Figure 5.7 the impact on value chain performances of such a higher capacity is presented.

Since the buffer storage assumption is only changed for truck value chains, these are the only ones affected. It can be discerned that the effect is largest for the CH_2 value chain, where LCOH goes from being close to as inexpensive as the "*Porsgrunn CH_2 pipeline*" value chain to being above 30% more expensive. The LOHC value chain also gets a significant increase in costs, but it has no major impact on its ranking among the value chains. The LH_2 value chain has a slight increase in LCOH while the effect on the NH_3 and MeOH value chains is negligible.

These results are in line with what could be expected and reflect the cost of storage for the different carriers, where storage of CH_2 in high pressure tanks is the most expensive option, followed by storage of LOHC where the cost is driven mainly by the high raw material cost for DBT. The results also stress the effect of buffer storage requirements on what is the most suitable value chain.
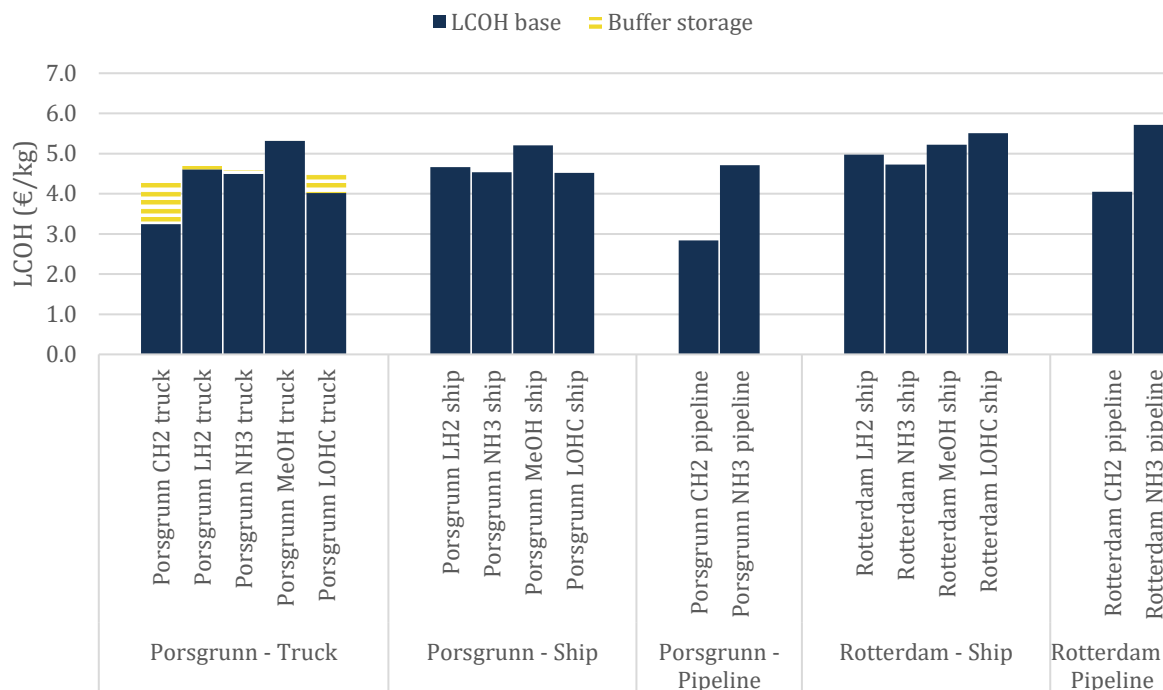
Figure 5.7. Sensitivity analysis of value chain performances for assuming longer buffer storage times for truck value chains.

5.2.3 Sensitivity for discount rate

The sensitivity of the results for a higher discount rate (12% instead of 6%) is visualised in Figure 5.8. As the graph shows, the discount rate has a significant impact on the LCOH of the value chains, but this impact is similar for all the value chains and does not change the ranking of them, with "CH_2 pipeline" still being the least expensive value chain for both Porsgrunn and Rotterdam.
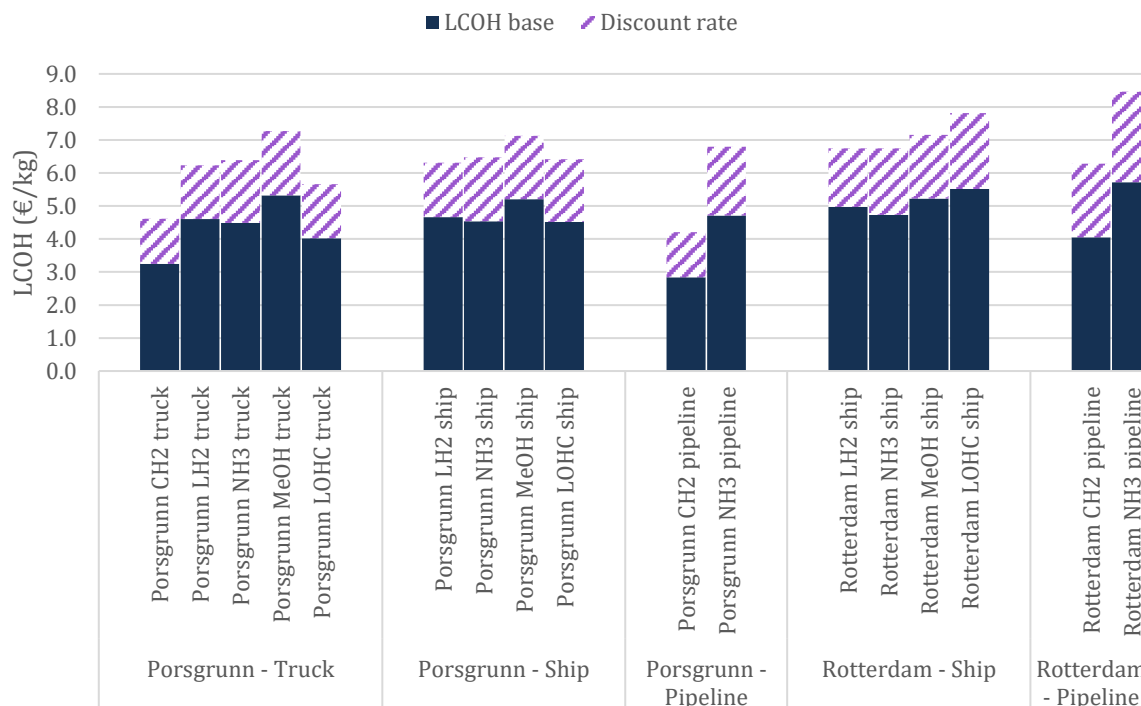

Figure 5.8. Sensitivity analysis of value chain performances for assuming a higher discount rate of 12.2% instead of the 6% assumed in the main results.

5.3 Literature comparison

The results can be compared to those of similar studies to allow for an assessment of the plausibility of the results. An important distinction to make before going further into this is that between LCOH for *hydrogen production* and LCOH for *landed cost of hydrogen*, where the latter include both the cost of production and of downstream processing and transport chains. The focus of this study is on LCOH for landed cost.

In Figure 5.9 comparisons for total LCOH are presented for relevant value chains. As the graph indicates there is a wide distribution of the results, which can be attributed to different underlying assumptions such as cost of electricity, transport distance and storage time.
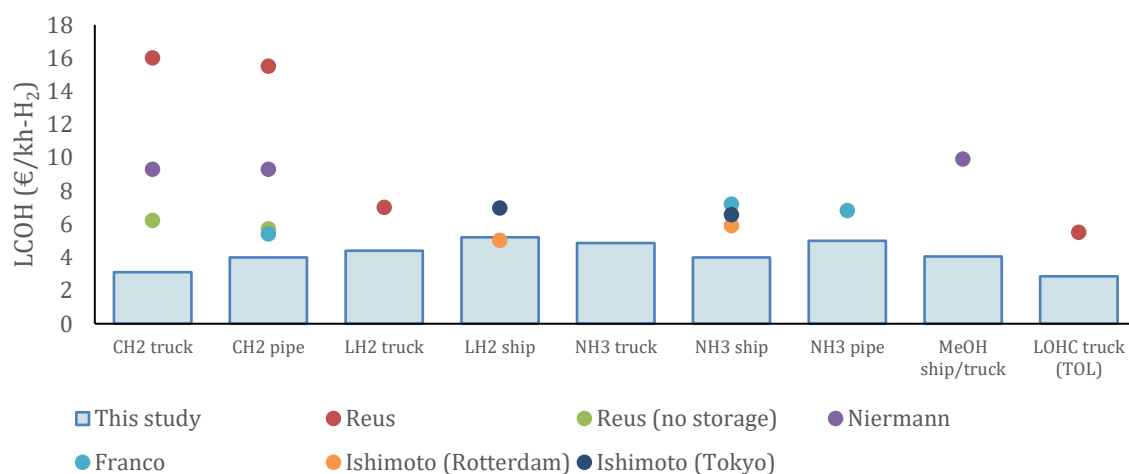
Figure 5.9. Literature comparison of whole-value chain LCOH for some selected value chains. For the values representing this study, values have been for the longest available value chain (Rotterdam) where that exists, meaning that the truck value chains are for the Porsgrunn case.

The production cost of hydrogen - including cost of electricity and electrolysis - constitute large parts of LCOH and as previously mentioned, the focus of the study is on the value chain steps downstream of the electrolyser. For this reason, an adjusted version of the graph in Figure 5.9 is presented in Figure 5.10, where only the LCOH of these downstream steps are included. It means that any differences in the production costs of hydrogen are neglected in this graph.

While the distribution of results is slightly smaller in Figure 5.10, large differences can still be seen for the different studies. Much of these differences can likely be explained by how assumptions for storage capacities and transport distances have been made. For instance, while this study assumes storage capacities corresponding to less than two days of production, Niermann et al. (2021) include both a buffer storage and 60 days of reserve storage. Also, fuel cost has only been implemented as percentage of CAPEX in this study, while other studies take more realistic approaches by calculating fuel costs as function of transport distance. Such differences in assumptions make it difficult to infer much from the literature comparison apart from stating that the sizing of value chain elements is of importance for the cost of the value chain.
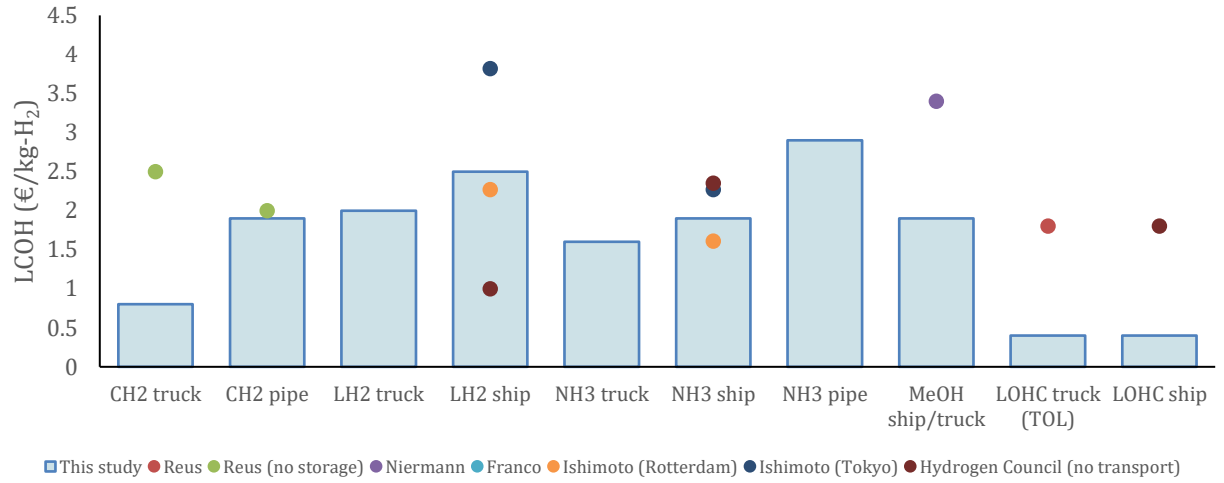
Figure 5.10. Literature comparison of processing/transport/storage-part LCOH for some selected value chains. For the values representing this study, values have been for the longest available value chain (Rotterdam) where that exists, meaning that the truck value chains are for the Porsgrunn case.

5.4 Direct utilisation of carriers

For two of the hydrogen carriers involved in the study - NH_3 and MeOH - the carrier themselves can be utilised directly in some applications, such as shipping fuel. This would allow for the two last steps of the value chains to be omitted, avoiding costs and losses associated with these steps. In Figure 5.11 and 5.12, the performance for the two least expensive Rotterdam-bound value chains with NH_3 and MeOH are presented as waterfall charts. The charts include a bar representing the market price of each product and, as the figures indicate, the levelised cost (including transport to Rotterdam) is significantly higher than market prices – more than two times higher for MeOH and more than three times higher for NH_3. The results for both carriers are ~50% higher than those from estimations by IRENA[1] (2021) and Hydrogen Council[2] (2021), but they are still in the same order of magnitude.
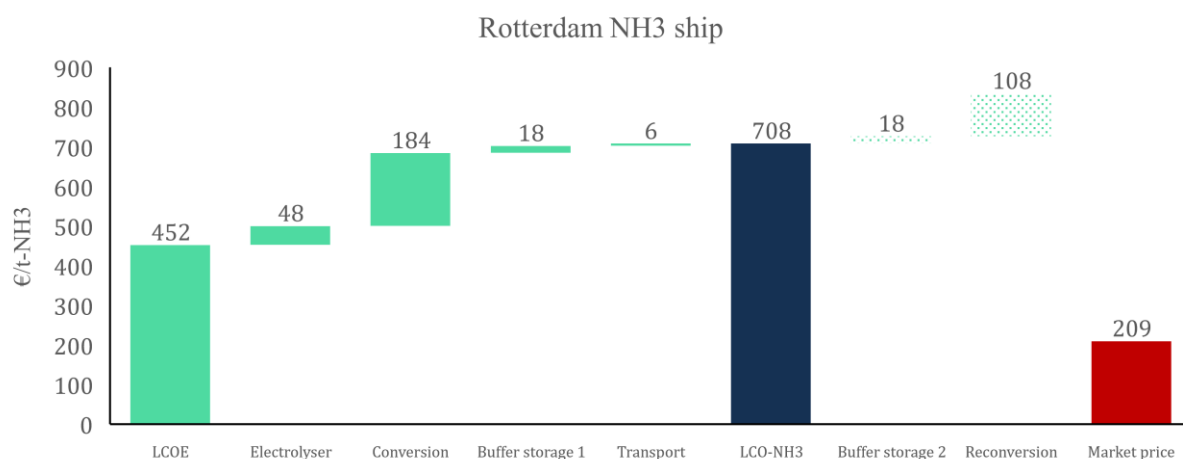
Figure 5.11. Graph showing how each step of the value chain contributes to levelised cost of NH_3 and how this compares to market prices of NH_3. The last two steps of the value chain ("Buffer storage 2" and "Reconversion") are not included in the LCO-NH_3.
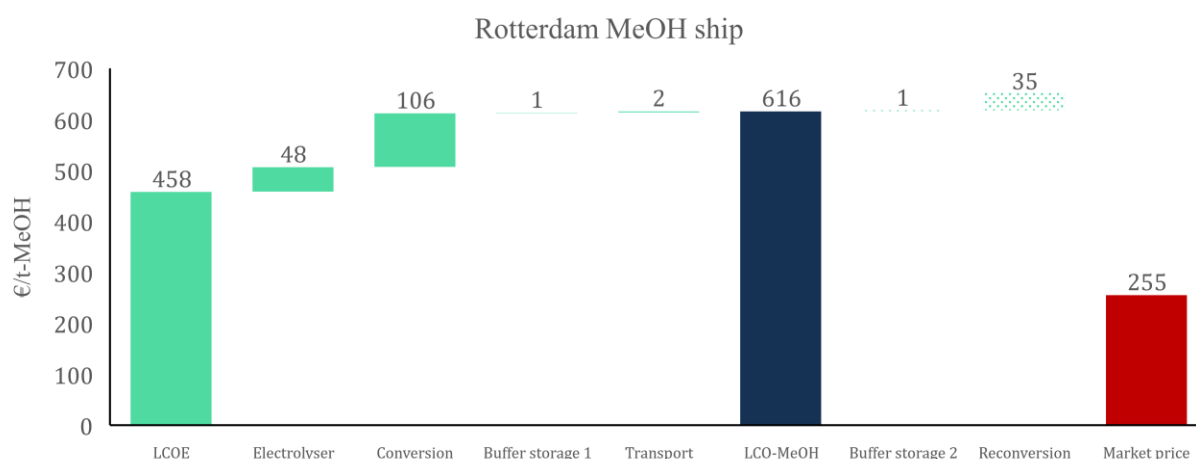
Figure 5.12. Graph showing how each step of the value chain contributes to levelised cost of MeOH and how this compares to market prices of MeOH. The last two steps of the value chain ("Buffer storage 2" and "Reconversion") are not included in the LCO-MeOH.

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[1] Estimating mature production cost levels for MeOH of 209-527 €/t
[2] Estimating 2030 landed cost (Saudi Arabia to Rotterdam) of NH_3 to 413 €/t

To be able to answer the third research question - about the possibility of direct utilisation of NH_3 and MeOH – the results of levelised costs for these (Figure 5.11 and 5.12) should be considered. The whole idea behind the hypothesis that direct utilisation of the carriers might increase the value chain potential is that it might decrease investment risk by giving access to more offtake markets. What determines if it does give access to more markets is if the case production cost for NH_3 and MeOH is low enough to be competitive on such markets.

As the results indicate, it is possible to produce and transport both these molecules to Rotterdam for a cost of around two (MeOH) or three (NH_3) times the mean market prices of their fossil counterparts. Without policy support - such as investment support for green NH_3 and MeOH or carbon prices for the fossil counterparts - the investigated value chains are not competitive with their fossil counterparts from a pure cost perspective. However, it is important to remember that the market price might differ between different market segments depending on the development of policy for those segments.

While green NH_3 and MeOH can be used as substitutes for their fossil counterparts, they might also be used as decarbonisation options in sectors where other forms of energy are currently used. In such cases price comparisons to fossil NH_3 and MeOH are less relevant and instead, what is more relevant is the future market price of green NH_3 and MeOH.

What the market price of green NH_3 and MeOH will be in the future is uncertain and depends on several different factors, ultimately boiling down to supply and demand of both chemicals. The demand depends, among other factors, on what policies are set up to steer the relevant sectors, the development of the price for conventional to-be-replaced fuels and what zero-carbon fuels that relevant industries set their focus on. For instance, one policy tool that might have a large impact is the EU ETS for which an extension to the shipping industry may currently be under way (European Parliament 2020). The supply of green NH_3 and MeOH depends on the level of deployment of other projects where – in the Nordics and across the world – a surge of initiatives has taken place during the last year (CIP 2021; Liquid Wind 2021; Statkraft 2020; Yara 2020). It should be noted that also blue NH_3 and MeOH are likely to act as competitors on the same market.

The uncertainties regarding future prices of green NH_3 and MeOH make it difficult to say to what extent the possibility of direct utilisation of these carriers affect the potential of their value chains. Deeper analysis on costs associated with their use in, for instance, the shipping sector might provide basis for more qualified estimations. Such analyses are, however, not undertaken within the scope of this thesis.

6 Discussion

In this discussion the main take-aways from the Results & analysis will first be summarised and discussed. These will then be connected to the purpose of the study. Limitations of the study will be discussed before suggestions for future studies are made. The discussion will then end with some reflections on the approach of the study.

The Results & analysis can be summarised in two main take-aways. Firstly, the value chain analysis shows that for the geographic cases and value chain configurations studied, the value chains based on compressed hydrogen and pipeline transport are the most promising value chains if H_2 is the intended end-product. These results hold for all the uncertainties and sensitivities tested within the study. Also, no significant difference in the share of different cost types can be seen between the value chains. Secondly, the analysis shows that direct utilisation of ammonia and methanol might make value chains based on these carriers reach a broader market, but that more studies are required to determine to what degree this might benefit such value chains. To generalise, these findings show that conversion of hydrogen should be avoided unless there are case specific circumstances (such as long storage time, long transport distance or demand for ammonia/methanol) that make them more efficient.

For the results regarding the most promising value chain, there is one aspect that goes missing in the analysis – flexibility. All the studied value chains assume that a 345 MW electrolyser – more than ten times the capacity of the largest electrolyser to date – is installed at year zero (2030), meaning that large volumes of hydrogen are produced already from the first year. In reality, it is possible that a pilot or demonstration plant would come as a first step, followed by a stepwise upscaling to a full-scale plant. Such an investment strategy would have implications for what value chains is optimal from a cost perspective. Pipelines do not provide the same flexibility as other transport modes, as it is not possible to scale up a pipeline to increase its capacity. In this aspect truck transport especially, but also ship transport, is more beneficial. The number of trucks could easily be increased as the scale of the electrolyser is increased, and as ships do not have to be dedicated for this specific plant this transport mode also offers more flexibility. What this means is that for the value chain configurations included in the study, the upfront investment (or CAPEX) is similar for all value chains, but especially the value chains based on truck transport – and also to some extent the ones based on ship transport – are more flexible to an investment strategy of stepwise scale-up.

Similar arguments could be used regarding what is the most promising hydrogen carrier. If a stepwise investment approach is used, it might be difficult to scale conversion plants for different hydrogen carriers. Instead, it might be more beneficial to start with hydrogen as compressed hydrogen for the initial stages, with the addition of a conversion unit when the scale is increased. That could also allow for more clarity regarding which carrier is better, as markets for green ammonia and methanol develop further.

The connection should also be made between the above take-aways and the purpose of the study, which is "*to investigate what value chains that are most promising from a techno-economic perspective, considering both hydrogen, ammonia and methanol as possible products.*". The study does look at how promising the value chains – included in the study – are, by comparing them in terms of LCOH. However, this is only done for 17 specific value chains. Firstly, there might be other geographic cases of relevance than the two included in the study where the different geographic conditions – e.g. distance or the availability of salt caverns for storage – give different results. Also, for the geographic cases set

up within the study, value chain elements such as the capacity, location and operation mode of the electrolyser or the capacity of buffer storage could be configured differently, giving even more possible value chains. Taking this into consideration, the study does investigate what value chains – out of a selection – that are most promising.

The surrounding systems is also an aspect that goes missing. Examples of surrounding systems that might impact which is the more promising value chain include the electricity and heat systems but also the industries present in the area. Interaction with the heat system could be through using nearby waste heat sources to cover process heat requirements, or through utilising waste heat from the value chain processes to cover nearby heat demands. The surrounding industrial system can have an impact through heat exchange, as mentioned, but can also be important for creating demand for the products. For instance, a nearby point of demand for methanol or ammonia might make a value chain using these chemicals as hydrogen carriers more promising. It could, for instance, be a chemical industry using methanol as a feedstock or a project for building up a refuelling hub for ammonia to the shipping sector. Such point demands might be small in number but can still play a large role for a business case and deserve more attention than given in this study.

Another aspect of the purpose relates to the aspects that are studied. The study assumes a techno-economical perspective, but this only constitutes one out of several aspects that might make a value chain more promising than others. Aspects that can complement this include the energy efficiency and environmental impact of value chains, but also their TRL and commercial viability. As the analysis of ammonia and methanol value chains showed, the future supply and demand price dynamics for the end-products can also play a large role in what value chains are more promising.

6.1 Limitations

There are limitations of the study that should be mentioned to allow for a judgement of the applicability of the results. Some of the limitations are products of the approach of the study, performed as a high-level comparison of a large number of value chains but undertaken within the limits of a master thesis, and thus simplifications have been made at all steps involved.

Firstly, the selection of parameters can have large impact on results, as shown in the study of uncertainties. Still, the uncertainties investigated in the study do not cover all parameter areas where uncertainties exist. Examples of parameters where uncertainties are likely to exist (and might impact the results) include the cost for installing pipelines and for liquid hydrogen ships. The CAPEX for pipeline construction for the Porsgrunn cases represent a particular limitation here, as the assumption of a straight pipeline (without hilly terrain) likely underestimates costs and that higher cost might mean that the "CH$_2$ pipeline" value chain is no longer the least expensive value chain for Porsgrunn. The uncertainties for pipelines and ships – as well as other uncertainties not tested – were not tested since no significant span of values was found in the data collection.

Another limitation, that is mentioned in the previous paragraph, is that the configuration of value chain can have a large impact on results, as demonstrated by the sensitivity-testing of buffer storage capacities. Nevertheless, there is no certainty that the configurations investigated in the study represent optimal or even plausible configurations.

The implementation of heat supply is one part of the model which can be criticised. It is assumed that hydrogen is used to cover all heat demands, although the use of such a high value energy source for heating could be questioned, especially considering that some of the heat demands do not require high temperature heat. Using waste heat to cover these demands could be a way of both decreasing costs and making efficient use of energy sources.

The assumption that heat is supplied using some of the produced hydrogen can also affect the comparability of the value chains, as not all value chains require heat. Using other forms of heat that are less expensive than the produced hydrogen might then have benefitted the value chains with higher heat demand. However, it is difficult to discern any implementation option that is more realistic here.

Lastly, the simplified implementation of fuel costs in the model might have implications for the results. Due to the limited time of the study the fuel costs were implemented as fixed OPEX, adding 12% of the vessel CAPEX every year. This percentage was assumed to be similar to the other OPEX of these transport vessels, although no evidence base was found for this assumption. A better solution would be to implement the fuel costs similarly to how the cost of electricity was implemented for the conversion/reconversion units – as a variable OPEX dependent on the travel distance by transport vessels. Another solution could be to assume that the transport vessels are fuelled by the transported hydrogen carrier, although this would require more detailed cost analysis of the vehicles.

6.2 Future studies

The limited scope of this study means that there are several aspects of Power-to-Hydrogen and Power-to-X value chains that have not been considered. Below follows recommendations of topics for future studies.

Value chain optimisation. The configurations of value chains investigated in this study does only represent a few out of many possible configurations. This makes it interesting to see what effect a value chain optimisation might have, where the most interesting configuration parameters are optimised for the lowest LCOH. Examples of parameters that could be optimised are the electrolyser capacity, conversion unit capacity, buffer storage capacity and number of transport vessels.

Efficient heat integration. There are several value chain steps involving heat in some way. Investigation of the potential to use waste heat to cover heating demands mainly of reconversion units would be of interest to see how this can improve the economics of investments, but also how it can improve energy efficiency at a higher system level. Additionally, studies of how the heat produced from the electrolyser and conversion units could be used would also be of interest. Both investigations of surplus and demand of heat could be done within a specific case context, looking to what sources of waste heat and what possible users of surplus heat that exist in the vicinity.

Breakeven prices for ammonia and methanol. To get a better understanding of the potential of utilising green ammonia and methanol directly, a study of breakeven prices for these in different sectors would be of interest. As discussed in this study, the future market prices of these are uncertain and depend on several different factors. Still, estimations and scenarios of future price could be used as reference points when investigating the potential of P2H and P2X value chains.

6.3 Reflections

The approach used in this master thesis has been to use a high-level value chain cost evaluation to compare the potential of value chains, an approach that has both strengths and weaknesses.

One of the main benefits of using this approach is that it offers a relatively quick way of comparing different value chain options, results of which could be of use both for investors in P2H and P2X investments and for decision makers regarding, for instance, decisions on publicly financed infrastructure.

The main drawbacks of the approach can be connected to the same reasons as the benefits – the high-level characteristic of the evaluation. While it means that a quick comparison is facilitated, it also means that detail is lost in the process of simplifications, details that might be of more or less importance. Another drawback is related to the process of cost evaluation. As it is a process looking at costs for facilities that are not yet built, there is no way to know costs for certain but instead cost estimations must be used. This always imply some degree of uncertainty, as costs for electrical infrastructure and chemical plants can differ from case to case. However, when it comes to costs for future investments, it is difficult to see any alternative to using some form of estimations.

7 Conclusions

The results of this study can be concluded in three main take-aways, relating to the three research questions set up.

Regarding the first research question, about the most promising value chains, the value chain comparison – including the testing of uncertainties and sensitivities – shows that the value chains based on compressed hydrogen and pipeline transport are clearly those with the lowest levelised cost of hydrogen. However, the result for Porsgrunn might be different, were the impact of hilly terrain to be considered in the CAPEX for pipelines. Broadly, this could be said to be comparable to results of previous studies, considering the relatively short distances and low production volumes considered in this study.

For the second research question, no significant difference in the composition of cost types was found between the value chains.

In response to the third research question – about potential of direct utilisation of ammonia and methanol – it is concluded that this **might** increase the potential of such value chains, but that further analysis is required to estimate future prices and demand levels for green ammonia and methanol.

Broadening the context from the specific cases, configurations and aspects studied in this thesis, consideration should be taken to that the optimal value chain for a case is dependent on several factors. Such factors could be flexibility of investment, energy efficiency and environmental impact of value chains or certain geographic context such as the presence of salt caverns for hydrogen storage or large demand points for any of the products involved.

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Appendix

The parameter values used in the study and presented in the below tables constitute the best estimates based on different sources. The sources used are Bartels (2008), IEA (2019a), IRENA (2021), H21 North of England (2018), Niermann, Beckendorff et al. (2019), Niermann, Drünert et al. (2019), Niermann et al. (2021), Reuβ et al. (2017), Sekkesæter (2019) and Teichmann et al. (2012).

Table A1. Overview of elements used in the different value chains (OSWF: offshore wind farm, HVDC: high voltage direct current, HPT: high pressure tanks, CT: cryogenic tanks, MOT: mineral oil tanks).

	CH_2	LH_2	NH_3	MeOH	LOHC
Power source	OSWF	OSWF	OSWF	OSWF	OSWF
Transmission	HVDC	HVDC	HVDC	HVDC	HVDC
Electrolysis	Alkaline	Alkaline	Alkaline	Alkaline	Alkaline
Conversion	Compression to 350 bar	Liquefaction	NH_3 synthesis	MeOH synthesis	LOHC hydrogenation
Buffer storage	HPT	CT	Cylindrical tanks	MOT	MOT
Transport	Pipeline / trucks	Trucks / LH_2 ship	Pipeline / trucks / ship	Trucks / ship	Trucks / ship
Receiving buffer storage	HPT	CT	Cylindrical tanks	MOT	MOT
Reconversion	-	Gasification	NH_3 cracking	MeOH dehydrogenation	LOHC dehydrogenation

Table A2. Parameters used for the electric supply modules. All value chains assume the same values for these parameters.

	Capacity	CAPEX	OPEX	Efficiency*	Lifetime
Unit	MW	M€	% of CAPEX	%	Years
Offshore wind farm	1 200	1 356	3.6	98.5	25
HVDC station offshore	1 182	536	2	99.5	25
HV DC transport cable offshore	1 176	200	2.5	99.1	25
HV DC transport cable onshore	1 166	1	0.05	99.1	25
HVDC station onshore	1 155	150	0.07	99.5	25
Grid connection electricity	804	-	-	99.9	25
HV station electrolyser onshore	347	45	0.07	99.5	25

Table A3. Electrolyser module assumptions.

	Unit	Value
Capacity	*MW*	345
CAPEX	*M€*	52
Efficiency	*%*	71
Time before stack replacement	*Full load hours*	60 000
Stack replacement cost	*M€*	68
Lifetime	*Years*	25

Table A4. Conversion and reconversion module assumptions.

	Unit	CH₂	LH₂	NH₃	MeOH	LOHC
Conversion						
Reference capacity	*t/d*	0.72	50	388	0.7	0.7
Reference CAPEX	*M€*	0.3	105	360	1.3	1.2
Reference CEPCI (year)	-	607.5 (2019)	567.3 (2018)	575.4 (2008)	607.5 (2019)	607.5 (2019)
Scaling factor	-	0.83	0.65	0.6	0.6	0.6
Capacity (input)	*t-H₂/d*	176.2	176.2	176.2	176.2	176.2
OPEX	*% of CAPEX*	4	8	4	4	4
H₂ throughput efficiency	-	100%	100%	100%	66.7%	100%
Electricity demand	*kWh/kg-H₂*	1.1	7.5	1.58	4.3	
Heating demand	*kWh/kg-H₂*	-	-	-	-	-
Feedstock requirement	*kg-CO₂/kg-H₂ or kg-DBT/kg-H₂*	-	-	-	7.3	0.0157*
Reconversion						
Reference capacity	*t/d*	-	1220	725	0.7	300
Reference CAPEX	*M€*	-	217	385	0.7	30
Reference CEPCI (year)	-	-	567.3 (2018)	607.5 (2019)	607.5 (2019)	567.5 (2017)
Scaling factor	-	-	0.66	0.6	0.6	0.6
Capacity (input)	*t-H₂/d*	-	176.2	176.2	176.2	176.2
OPEX	*% of CAPEX*	-	8	4	4	4
Electricity demand	*kWh/kg-H₂*	-	0.03	0.013	4.5	0.1
Variable OPEX	*€/MW-H₂*	-	4.8	0.014	5.6	0.1
Heating demand	*kWh/kg-H₂*			4.2	3.2	11.6
H₂ throughput efficiency**	-	-	99.9%	88.0%	90.8%	74.4%

*Required to replenish the losses of 0.1% that occur for each cycle.

** Including losses through heating with hydrogen.

Table A5. Truck and ship transport module assumptions. Parameters that have different values for the geographical cases are expressed as *Value for Porsgrunn* / *Value for Rotterdam*.

	Unit	CH₂	LH₂	NH₃	MeOH	LOHC
Truck						
Payload capacity	t-H₂	0.72	4.5	4.0	3.1	1.3
Average speed	km/h	60	60	60	60	60
Utilisation	hours/year	3500	3500	3500	3500	3500
Loading/unloading time	hours	2	3	2	2	1.5
Raw material cost	€/kg-DBT	-	-	-	-	4
No. of units required*	-	271	50	50	41	133
CAPEX/truck	M€	0.16	0.16	0.16	0.16	0.16
OPEX/truck	% of CAPEX	12	12	12	12	12
CAPEX/trailer	M€	0.550	0.860	0.150	0.150	0.150
OPEX/trailer	% of CAPEX	2	2	2	2	2
DBT CAPEX/unit	M€	-	-	-	-	0.087
H₂ throughput	%	variable	variable	variable	variable	variable
Lifetime	Years	25	25	25	25	25
Ship						
Payload capacity	t-H₂	-	354	3410	3955	5200
Average speed	Km/h	-	30	30	30	30
Utilisation	Hours/year	-	8000	8000	8000	8000
Loading/unloading time	Hours	-	2	2	2	2
Raw material cost	€/kg-DBT	-	-	-	-	4
Boil-off gas	% / day	-	0.2	0.2	-	-
No. of units required*	-	-	0.38 / 0.82	0.22 / 0.48	0.18 / 0.39	0.43 / 0.93
Ship CAPEX / unit	M€	-	15.3	7.1	3.5	3.5
DBT CAPEX / unit	M€	-	-	-	-	0.087
H₂ throughput	%	variable	variable	variable	variable	variable
Lifetime	Years	25	25	25	25	25

*Rounded up to closest integer to calculate ship CAPEX.

Table A6. Exchange rates used in the data collection. Source: Yearly average from 1991 to 2020.

Currency conversion	Conversion factor
NOK → EUR	0.118
USD → EUR	0.837
GBP → EUR	1.312

Table A7. Pipeline transport module assumptions. Parameters that have different values for the geographical cases are expressed as *Value for Porsgrunn* / *Value for Rotterdam*.

	Unit	CH₂	NH₃
Capacity	MW H₂	244	237
Specific CAPEX	M€ / km	0.98 / 1.57	0.63 / 1.01
OPEX	% of CAPEX	0.5	0.5
H₂ throughput	%	100	100
Lifetime	Years	30	30

Table A8. Buffer (before and after transportation) module assumptions. Parameters that have different values for different value chains are expressed as *Value "Porsgrunn truck"* / *Value "Porsgrunn ship"* / *Value "Rotterdam ship"*.

	Unit	CH₂	LH₂	NH₃	MeOH	LOHC
Capacity*	t-H₂	3 / - / -	18 / 1252 / 2696	15 / 1235 / 2659	12 / 815 / 1755	13 / 1235 / 2659
Scaling factor	-	1	1	1	1	1
Boil-off	% / day	-	0.3	0.08	-	-
Spec. CAPEX	€/kg-H₂	380	25	9.5	1.16	66.7
OPEX	% of CAPEX	4	4	4	4	4
H₂ throughput	%	variable	variable	variable	variable	variable
Lifetime	Years	25	25	25	25	25

Table A9. Spans used for uncertainties. The CAPEX for electrolyser is for a 100 MW electrolyser. The CAPEX for conversion and reconversion units are for the capacities specified in Table A4. Reconversion is not required for CH₂.

		Unit	Low	High	Sources
Electrolyser efficiency		%	65	71	(IEA 2019a)
Electrolyser CAPEX		€/kW	96	711	(IEA 2019a)
Conversion CAPEX	CH₂	M€	33.5	-	(Niermann et al. 2021)
	LH₂	M€	267.8	910.3	**Low:** (Stolzenburg et al. 2013) **High:** (H21 North of England 2018)
	NH₃	M€	244.6	270.9	**Low:** , **High:** (H21 North of England 2018)
	MeOH	M€	48.8	264.3	**Low:** (Niermann et al. 2021), **High:** (IRENA 2021)*
	LOHC	M€	33.0	88.6	**Low:** (Niermann et al. 2021), **High:** (IEA 2019a)
Reconversion CAPEX	CH₂	M€	-	-	-
	LH₂	M€	61.4	-	(H21 North of England 2018)
	NH₃	M€	156	263.2	**Low:** (IEA 2019a), **High**: (H21 North of England 2018)
	MeOH	M€	14.8	14.8	(Niermann et al. 2021)
	LOHC	M€	23.7	23.7	(Reuß et al. 2017)
CO₂ feedstock cost		€/t-CO₂	41.9	125.6	(IRENA 2021)

*This value is based on numbers in the report for an actual plant in Norway, where electrolyser costs are included. The CAPEX excluding electrolyser has been calculated assuming an electrolyser cost of 1068 €/kW.