Techno-economic analysis of transporting hydrogen and hydrogen based energy carriers in the Netherlands

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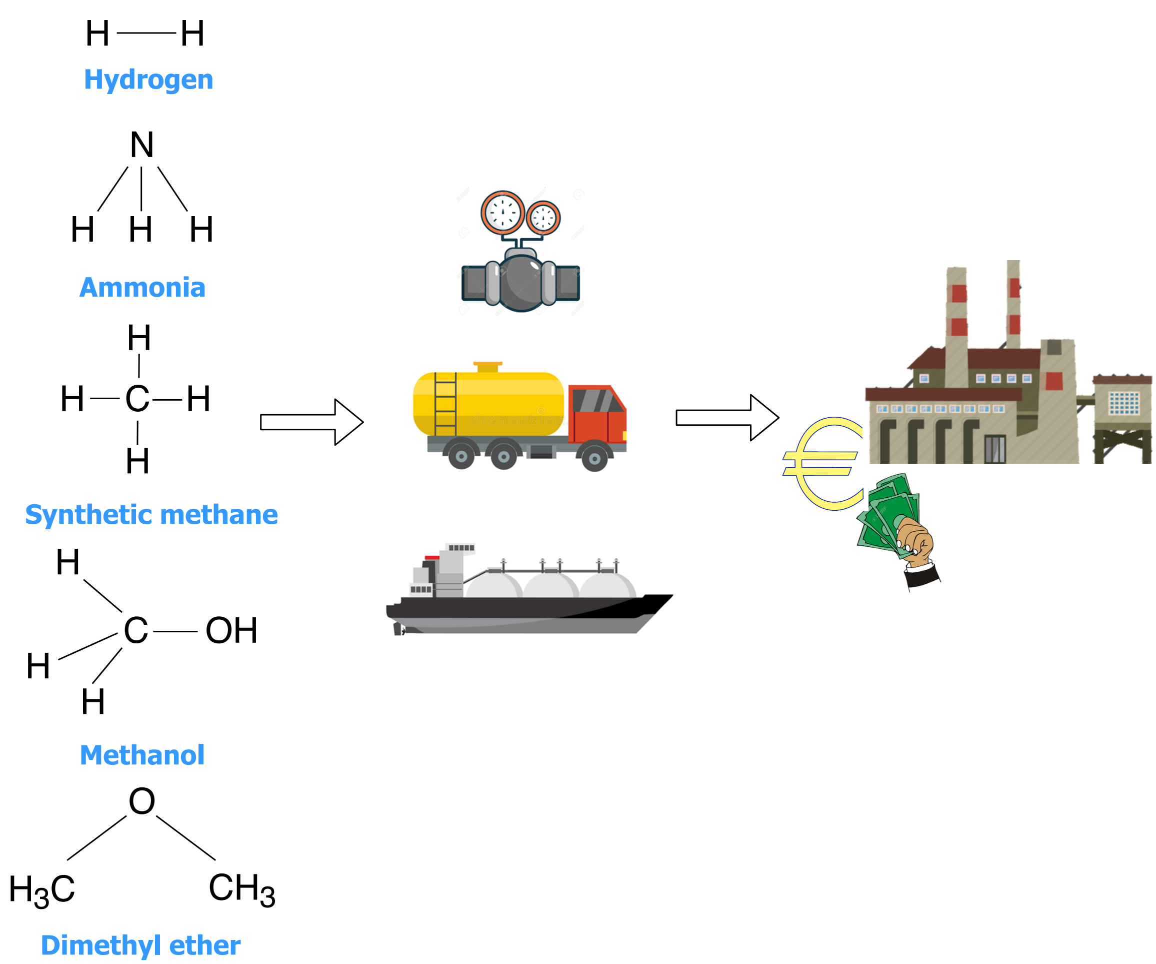

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by

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Abstract

As the transition to a low-carbon economy is imminent in the view of global warming and climate change, there comes a need to identify energy carriers that can completely or partially replace fossil fuels that are used today. Green hydrogen in this respect has been proposed and researched into as a possible replacement for currently used fossil fuels. Despite hydrogen being a relatively cleaner source of energy and a good energy storage medium, the transportation and storage of hydrogen acts as a barrier for the large-scale implementation of a hydrogen economy. The low density of hydrogen requires it to be compressed to high pressures or liquefied to transport and store it while the explosive nature makes it difficult to handle hydrogen. These drawbacks open up opportunities for other hydrogen energy carriers to be considered instead of hydrogen.

The aim of this thesis is to identify bottlenecks in the supply chain of hydrogen and hydrogen energy carriers which include production, storage, transportation, imports and reforming of the energy carriers. The hydrogen energy carriers that have been shortlisted other than hydrogen include ammonia, methanol, dimethyl ether and synthetic methane while the transport modes considered include road transport, maritime shipping and pipeline transport. The Netherlands is chosen as a case study taking into account the demand for hydrogen across the six industrial clusters for the year 2050. The demand for hydrogen includes hydrogen for energy and for feedstock which resulted in a total demand of 444 PJ for the year 2050. Hydrogen production which also serves as a starting point for the production of the other energy carriers, is based on the predicted 15 GW surplus offshore wind energy available in the Netherlands from the North Sea wind farms by the year 2050. Considering the supply and demand, the supply chain of each energy carrier within the three transport modes are modelled resulting in the estimation of the energy efficiency and the system costs. Further, region specific costs are estimated to identify what factors affect the costs of delivering the energy carriers to the different regions in the Netherlands.

The results indicate that pipeline transport was the most economical transport mode followed closely by liquid road transport. Compressed road transport was not as attractive, as the high transport pressures resulted in high loading and unloading costs and lower system efficiencies. Hydrogen pipelines was the most economical energy carrier and transport mode followed by liquid hydrogen road transport and ammonia pipeline. Transporting synthetic methane was the most expensive energy carrier across all transport modes while methanol and DME had very similar system costs. The production and import costs were the two main factors determining the system costs while transport costs had an vital impact only in the case of compressed road transport. Storage and reforming costs of the energy carrier were almost negligible in most cases. The Capex and the efficiency of the hydrogen electrolyser played a major role in determining the production costs of all the energy carriers. Ammonia reforming was identified as a bottleneck pushing the system costs of transporting ammonia higher than the system costs of transporting hydrogen. Liquefaction of hydrogen and synthetic methane resulted in higher import costs for these energy carriers and higher transport costs when transported as a liquid by road, in comparison to the other three energy carriers.

Estimating region specific costs for hydrogen pipeline transport resulted in a variation in the costs of hydrogen delivered to the different regions in the Netherlands. The allocation of cheaper imports and relatively expensive domestic production across the six industrial clusters in the Netherlands was a major factor in determining the costs of the energy carrier delivered to the industrial clusters.

Contents

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1 Introduction

This chapter will start off with an introduction, which will first look into why 1) there exists a need for hydrogen based energy carriers, and 2) a need to explore different modes of transporting the hydrogen based energy carriers. This will be followed by a literature review, highlighting work done in this field. Following the literature review, the research gap will be discussed and the research questions that this thesis will aim to answer.

1.1 Introduction

The current global energy mix is still dominated by fossil fuels with coal remaining at the top spot followed by natural gas in second (IEA, 2018). The discovery of shale oil in North America and the growth of the Asian and African markets mainly China, have strengthened the demand for fossil fuels (IEA, 2018). China's increasing demand for natural gas and the shale oil revolution have further flooded the markets with new suppliers for fossil fuel derived energy. These elements have put the globe on a different trajectory that one would not expect to envision, especially when there is a need to combat climate change (IEA, 2018). The 2018 IPCC special report highlights the consequences of reaching 1.5°C above pre-industrial levels, which is clear enough evidence suggesting that this course of action may lead to disastrous effects (IPCC, 2018). On the bright side, the share of renewable energy in the power mix stands at 25% as of 2018 and is expected to grow to just over 40% by 2040 because of falling costs and favourable governmental policies (IEA, 2018).

Despite the better integration of renewable energy into the energy mix, there is still a need to decarbonise the global economy at a faster rate to keep up with the Paris agreement goals (IEA, 2015). Compared to the emission levels at 2015, annual emissions should be reduced by 85% by 2050, to limit global warming to 2°C above pre-industrial levels as per the Paris agreement (IEA, 2015). New fuels for transportation, more energy efficient systems and carbon capture in industries are some of the measures that would require global deployment to achieve the aforementioned target (IEA, 2015). In this respect, the hydrogen economy is seen as alternative solution to decarbonise the different sectors (IEA, 2019)(Wulf & Zapp, 2018)(Weber et al., 2013). Hydrogen (green) produced in a renewable manner through electrolysis, is a low-carbon energy source that can be seen as a possible transportation fuel, fuel source for power production and serve as an energy storage system for the integration of more renewable energy systems in the energy mix (IEA, 2019).

Nevertheless, hydrogen has its drawbacks. Hydrogen cannot be found in its pure form and thereby needs to be sourced either from fuels like natural gas, or has to be produced in a renewable manner through the electrolysis of water (Pudukudy, Yaakob, Mohammad, & Narayanan, 2014). Hydrogen has a low volumetric energy density, as an example when compared to gasoline, hydrogen would need three times the volume for the same amount of energy (Aakko-saksa, Cook, Kiviaho, & Repo, 2018). Further, the capability of hydrogen to leak due to its low density and its flammable and explosive nature, makes handling and transporting hydrogen difficult (Rusin & Stolecka, 2017).

Like any other technology that is introduced into the market, renewable hydrogen technologies faces low return on investments, which instills the first adopter syndrome in governments worldwide (World Energy Council, 2019). Despite this, an increasing number of pilots and projects are emerging across the world (T. E. Lipman, Edwards, & Brooks, 2006). The abundance of the hydrogen atom in many hydrocarbons, allow us to explore whether it can be technically easier and more economical to transport these hydrocarbons rather than hydrogen itself (Aakko-saksa et al., 2018). Some of the hydrocarbons that are seen as possible alternatives to hydrogen are: ammonia, methanol, formic acid, dimethyl ether, oxymethyl ether, methane, metal hydrides, liquid organic hydrogen carriers (LOHC) and hydrogen in slurry form (Aakko-saksa et al., 2018). Majority of these products have been commercially produced for years and transported at a large scale. The knowledge gained through the large scale production and transport of these hydrocarbons, serves as an advantage over hydrogen. In the specific case of the Netherlands, which has one of the largest industrial chemical clusters globally, the potential of using any of the above mentioned energy carriers is applying knowledge gained over the past years.

In the specific case of the Netherlands, hydrogen would be used primarily for power production in power plants and for industries (Gasunie, 2018). This is primarily due to the industrial growth rate which is expected grow by 1.6% industrial per annum till 2050, as per the Gasunie 2050 survey and 1% by per annum till 2050, as per an Ecofys (Navigant) report (Gasunie, 2018)(Ecofys, 2018). Despite this, for the Netherlands to stay within the 2°C target, 90% - 100 % of CO_2 emissions have to reduced by 2050, in reference to 1990 (van Vuuren, Boot, Ros, Hof, & den Elzen, 2017). This would imply that an almost full decarbonization of the energy sector would be needed (van Vuuren et al., 2017). In this respect, the hydrogen economy can play a big role by balancing the decarbonization of the economy while maintaining a good industrial growth rate. It has to be noted, that eventhough industries are expected to grow, energy consumption is expected to decrease in the future due to energy efficiency measures that are expected to be taken (Gasunie, 2018)(Ecofys, 2018).

1.2 Literature review

A literature review was done in the area, of the transport of hydrogen and/or hydrogen energy carriers. Most of the papers reviewed, discussed how hydrogen based energy carriers can be used to produce hydrogen or serve as a hydrogen storage system (Lamb, Dolan, & Kennedy, 2019)(Chen, Yan, Song, & Xu, 2018)(Anzelmo, Wilcox, & Liguori, 2018)(De Wild & Verhaak, 2000)(Amirshaghaghi, Eliassi, & Taghizadeh, 2014).

The limited number of papers that have looked into the transport of hydrogen and/or hydrogen energy carriers, have been restricted in terms of the level of the analysis done or the number of energy carriers that have been considered. Aakko-saksa et al., reviewed potential energy carriers and further analysed the potential for storage and transportation of gaseous H_2, liquid H_2, liquid organic hydrogen carriers and circular methanol (Aakko-saksa et al., 2018). In the same paper, the authors call for a need to do a techno-economic analysis for the different hydrogen energy carriers, as this will provide the understanding needed to pave the way for the successful integration of any of the energy carriers into the energy infrastructure (Aakko-saksa et al., 2018). Singh et al., did a component level review on the transport of hydrogen using different transport modes to deliver hydrogen from the production site to fuelling stations (Singh et al., 2015). The authors concluded that for areas which have a high hydrogen demand, strategically laid pipelines serve as the best transportation mode (Singh et al., 2015). For areas that do not have access to pipelines but have relatively high demands, cryogenic trucks are economical while compressed hydrogen road transport is used for hauling hydrogen towards areas of low demand (Singh et al., 2015).

System level analysis on the transport of hydrogen and/or hydrogen energy carriers, could be found in some literature but focused on hydrogen only or hydrogen in comparison with a few other hydrogen energy carriers. In this context, a system level analysis refers to a techno-economic analysis taking into account all the components from processing and storing the energy carrier at the source, to transporting the energy carrier, to processing and storing the energy carrier at the destination. In most cases, the papers looked into either pipeline or road transport of the energy carriers. Yang and Ogden focused on the delivery of hydrogen using trucks and pipelines on a system level (Yang & Ogden, 2007). The authors had modelled two scenarios where hydrogen was transported: 1)

From a central production plant to a single destination and 2) From a central production plant to a number of refuelling stations (Yang & Ogden, 2007). The two scenarios differentiated the system costs of hydrogen delivery between a transmission and distribution model (Yang & Ogden, 2007). Reuß et al., discusses a flexible hydrogen infrastructure using pipeline and road trailers for hydrogen transportation, taking into account gaseous H_2, liquid H_2 and liquid organic hydrogen carriers (Reuß et al., 2017). The authors did a system level analysis with multiple pathways for the storage and delivery of the aforementioned energy carriers (Reuß et al., 2017). The analysis resulted in the comparison of the costs and emissions for each pathway (Reuß et al., 2017). The authors concluded that liquid organic hydrogen carriers are promising hydrogen energy carriers for the hydrogen supply chain from an economic stand point (Reuß et al., 2017).

Weber et al., did a detailed study focused on pipeline transport of hydrogen across Germany using Geographical Information System Environment (GIS) (Weber et al., 2013). The research assumed hydrogen to be either produced from electrolysers powered by onshore and offshore wind farms, or by lignite gasification (Weber et al., 2013). The authors developed a tool to generate a pipeline network between the sources and sink, taking into account technical and societal factor (Weber et al., 2013). Wulf and Zapp, compared the direct and the indirect greenhouse gas emissions costs of transporting hydrogen using liquid organic hydrogen carriers and as liquid H_2 (Wulf & Zapp, 2018). The authors went a step further by comparing costs of using natural gas and wind energy for the system processes required to transport liquid organic hydrogen carriers and liquid H_2 (Wulf & Zapp, 2018). The authors concluded from an economic standpoint, transporting liquid organic hydrogen carriers were more economical than liquid H_2 but from an environmental stand point, liquid organic hydrogen carriers performed worse than liquid H_2 due to the extra heat needed for dehydrogenation and the low transport capacity of the hydrogen molecule by liquid organic hydrogen carriers (Wulf & Zapp, 2018).

Aziz et al., compares the energy efficiency of producing, storing, transporting and utilizing liquid H_2, methylcyclohexane which is a type of liquid organic hydrogen carrier, and ammonia as a hydrogen energy carrier (Aziz, Oda, & Kashiwagi, 2019). In the case of ammonia, the authors also looked into the energy efficiency of using ammonia directly and not as an energy carrier (Aziz et al., 2019). The authors took estimates of the energy consumed in each process and losses during each step to calculate a final energy efficiency of using the three as a hydrogen energy carrier (Aziz et al., 2019). The authors also estimate the prices for liquid H_2, methylcyclohexane and ammonia during the year 2030 and 2050. The paper concludes that if pure hydrogen is not required, then the direct use of ammonia as a fuel is the most energy efficient and economical (Aziz et al., 2019).

Olah A. suggests that the methanol economy is a good alternative to the hydrogen economy (Olah A., 2009). The author argues that compared to hydrogen, methanol and DME are safe to store and transport (Olah A., 2009). The author further argues that methanol is the simplest and safest liquid oxygenated hydrocarbon, which is produced in large quantities and has an existing infrastructure that can be used (Olah A., 2009). This gives methanol an edge over hydrogen, for which infrastructure has to be adapted to, to facilitate its transport and storage (Olah A., 2009). The author went on further sketching a possible framework for the methanol economy (Olah A., 2009).

In the specific case of the Netherlands, the Energy Research Centre in the Netherlands (ECN) had published a research paper in 2007 focused on a system level analysis of the transport of hydrogen in the Netherlands by pipeline. The paper aimed at providing hydrogen for the transport sector, and use in combined heat and power plants (CHP) for domestic usage i.e households for heat and electricity (Smit, Weeda, & de Groot, 2007). The authors focused on how the hydrogen demand will develop across regions in the Netherlands overtime while predicting the reduction of costs of fuel cells and hydrogen produced through steam methane reforming plants till the year 2050 (Smit et al., 2007). The proposed pipeline infrastructure was modelled using the current natural gas infrastructure (Smit et al., 2007). The authors concluded that the hydrogen pipeline they had modelled would cost 11 billion euros while a fully developed pipeline infrastructure for the Netherlands, would cost between 12 - 20 billion euros (Smit et al., 2007).

Murthy Konda et al., took into account various techno-economic assessments already done and predicted the optimal supply of hydrogen in the Netherlands for the transport sector (Murthy Konda, Shah, & Brandon, 2011). The authors had done a well to wheel analysis, assuming that hydrogen would be transported as liquid H_2 in tankers and compressed H_2 through trailer and pipelines (Murthy Konda et al., 2011). The hydrogen produced was assumed to be of non-renewable nature mostly through steam methane reforming on top of the existing supply of hydrogen as a by-product of the chemical industries (Murthy Konda et al., 2011). The authors took into account the CO_2 emissions and the associated costs in the model while generating the cost of hydrogen (Murthy Konda et al., 2011). The model predicted the share of fuel cells vehicles (FCEV) in the Netherlands and thereby determined the cost of the hydrogen, since the increasing demand of FCEVs would decrease the hydrogen costs. The authors concluded with Carbon Capture and Storage (CCS), 85% of CO_2 emissions could be avoided (Murthy Konda et al., 2011).

Multiple roadmaps for the Netherlands have been published drawing out futuristic scenarios where hydrogen will play an important role (van Wijk, 2018)(Gasunie, 2018)(Tennet & Gasunie, 2018).

The Northern Netherlands Innovation Board (NIB) had published a report Green Hydrogen Economy in Northern Netherlands which had focused on using offshore wind farms, solar farms and biomass gasification for hydrogen production (van Wijk, 2018). The production of hydrogen would be focused in the area of Delfzijl and Eemshaven in the north of the Netherlands with pipelines connected to Rotterdam and Germany (van Wijk, 2018). The report mentions that since the petrochemical industry would be one of the main recipients of hydrogen, the production of methanol and ammonia from renewable hydrogen is expected (van Wijk, 2018). The report also predicted the hydrogen demand to be 270 ktons by 2030 (van Wijk, 2018).

Gasunie published a 2050 survey report, where the estimated hydrogen demand would be 444PJ by 2050 (Gasunie, 2018). The report further states that the hydrogen will be produced offshore in the North Sea wind farm hub, onshore using electrolysers that would use surplus electricity, and some of the hydrogen would be imported (Gasunie, 2018). Another report 'Infrastructure Outlook 2050' by Tennet and Gasunie states the electricity grid and hydrogen network would be dependent on each other and multiple scenarios were taken into account and modelled (Tennet & Gasunie, 2018). The scenarios were based on the varying renewable energy generation and varying demands across the Netherlands (Tennet & Gasunie, 2018). A hydrogen pipeline network was modeled with the various scenarios showing explicitly the hydrogen flows across the Netherlands (Tennet & Gasunie, 2018).

1.3 Research gaps

Reviewing the literature, visible knowledge gaps exists in respect to: 1) A cost comparison between the transport of hydrogen and hydrogen energy carriers, which was limited to hydrogen and liquid organic hydrogen carriers in most papers, 2) A system level analysis of transporting the energy carriers using the various transport modes, which according to the current literature was extensively done for road and pipeline transport of hydrogen only. In the specific case of the Netherlands, research papers have done a system level analysis but only focused on the transport of hydrogen and that specific to either road or pipeline transport only. From the roadmaps, it was noticeable that the hydrogen economy only considered hydrogen as an energy carrier eventhough the report from

NIB pointed out, that there will be a market for ammonia and methanol in the future (van Wijk, 2018)(Gasunie, 2018)(Tennet & Gasunie, 2018).

The research gaps indicate that a system level analysis or rather research into the transport supply chain of hydrogen and hydrogen energy carriers were missing. Either research was focused on parts of a system or a system level analysis was done taking into account only hydrogen, and/or one hydrogen energy carrier. Therefore, a system level techno-economic analysis would be able to give a good indication of the system costs involved in transporting hydrogen based energy carriers and possible transport modes that can be considered for the hydrogen economy. The results would be able to provide a good comparison of hydrogen and hydrogen energy carriers in each transport mode, which can give insights into the bottlenecks in the hydrogen transport supply chain.

1.4 Research question

Reviewing the literature and taking into account the knowledge gap found, the research question was framed.

What are the key techno-economic trade-offs and hotspots in the supply chain of different renewable based energy carriers for a low-carbon scenario for the Netherlands in 2050?

1) What key technical factors will influence the feasibility of transporting the hydrogen and hydrogen energy carriers the most?

2) How do the system costs compare with each energy carrier across the different transport modes?

3) Are there differences between region specific and country level costs and if so, which factors trigger these differences?

2 Scope and Method

This chapter will start off with the scope of the thesis and will be followed by a flowchart describing the steps taken to answer the research questions with the method used and the respective outcome. This will be followed by a detailed breakdown of each method and outcome mentioned in the flowchart.

2.1 Scope

Since the thesis is based on the hydrogen economy, which in itself has been envisioned for the future, the thesis had to consider a year in the future where it is expected to have transport of hydrogen energy carriers on a large scale. The year 2050 was chosen as multiple roadmaps have indicated and made predictions/forecasts for the hydrogen economy for the year 2050 (Gasunie, 2018)(Tennet & Gasunie, 2018), which has been highlighted in the section 1.2. The Netherlands is taken as a case study for the thesis as the Dutch have been on the forefronts of the energy transition with multiple scenarios that have been developed by the government, research institutions and companies either towards a hydrogen economy or in general discussing the energy transition for the Netherlands (van Wijk, 2018)(Gasunie, 2018)(Tennet & Gasunie, 2018). Further, the Dutch chemical industry is one of the largest globally, which increases the probability that either the energy carriers mentioned in literature are already produced in the Netherlands or are being experimented with, at a pilot scale. This gives the Dutch an advantage, that knowledge is already available to implement large scale-transport of the energy carriers. Moreover, the country's renewable energy targets and decarbonisation ambitions will strengthen the need for renewable energy production in the country, which is a key factor for this thesis, as renewable production of hydrogen/energy carriers is used in this study.

The possible transport modes to transport the energy carriers are; Road, ship, rail and pipeline. As seen in section 1.2, many studies have either not considered rail transport as a possible transport mode or analysed it as a possible alternative to pipeline and road transport. Further, the US DRIVE roadmap also mentions that rail transport is met by limitations, such as the fixed transport routes which do not allowable for flexible delivery (US DRIVE, 2013). In the Netherlands, inland shipping is quite common with container terminals established in multiple areas in the Netherlands. One significant limitation in regard to inland shipping, is that container terminals do not have the infrastructure to handle the loading and unloading of gas and liquid bulk. This results in the only form of transporting the energy carriers, through ISO-containers on barges for inland shipping or establishing loading and unloading infrastructure for liquid and gases at source and destination ports. ISO-containers are containers that have been developed to transport gases and liquid, giving it the advantage to be handled like a normal container. Taking into account the limitations of rail transport and inland shipping, it is decided to consider maritime shipping, road and pipeline transport of the energy carriers.

2.2 Method flowchart

To answer the main research question, the three sub questions have to first be answered. Figure 1 is a flow chart that shows, how the thesis will be approached and how the research question and sub questions will be answered in a step by step manner. As seen in figure 1, there are seven steps, each that have an outcome that leads to the result expected to be achieved in this thesis. Each step and respective outcome is further discussed in the following sub-sections and chapters.

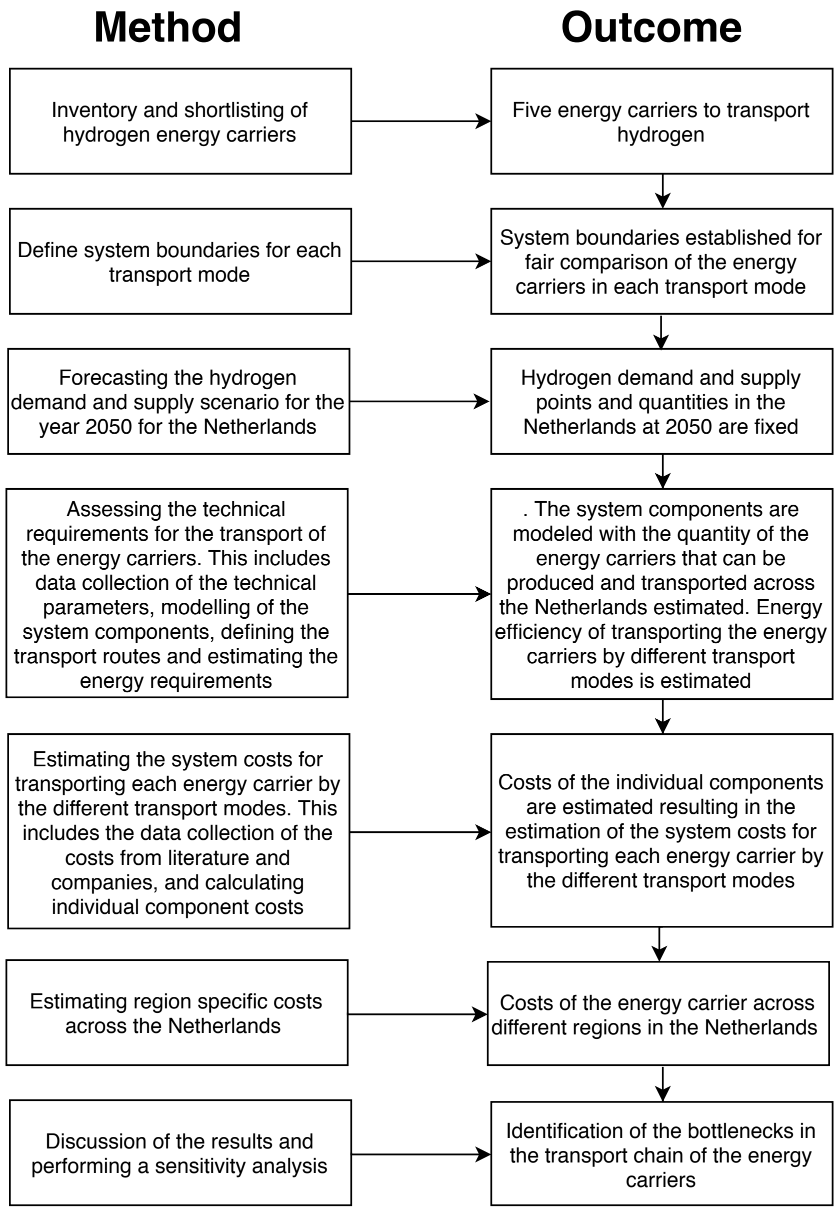

Figure 1: Method flowchart

2.2.1 Energy carriers

The first step is to review the hydrogen energy carriers that can be considered as possible alternatives to hydrogen. To do this, an inventory of all possible hydrogen energy carriers has to be made, by reviewing available literature. This will then be followed by the shortlisting the energy carriers as all possible energy carriers cannot be researched into. The shortlisting of the energy carriers is done by introducing three criteria; maturity of the energy carrier, data availability for the energy carrier and the knowledge available to handle and transport the energy carrier. The criteria - maturity of the energy carrier, will be able to classify the energy carriers as to whether they have been commercially produced and utilized or are produced and used only at a smaller scale in labs. The criteria - data availability for the energy carrier, will focus on whether there is available data in literature, or from companies to extract necessary information from, about the energy carrier. The criteria - knowledge available to handle and transport the energy carriers, will be able to classify the energy carriers as to whether companies have either transported the energy carriers or research has been done into how they can be transported safely without causing major accidents.

2.2.2 System boundaries

Since there are multiple transport modes to transport the energy carriers, it is necessary to make sure that each transport mode is assessed fairly with respect to each other. This will make sure that the results of the thesis are comparable. The system boundaries will make sure that each energy carrier will be assessed equally as the same system components will be accounted for in each transport mode.

2.2.3 Hydrogen demand and supply

To be able to evaluate the transport of the energy carriers, a scenario has to be established wherein the demand and supply for hydrogen is known. The quantity of hydrogen needed or produced in itself is not enough, as the points/locations of the supply and demand of hydrogen, would serve as the basis for the assumed transport network for the energy carriers. The imbalance in the supply and demand over multiple locations in the Netherlands will be the driver for the transportation of the energy carriers across the Netherlands.

2.2.4 Technical assessment

In this step, the technical requirements to transport the energy carriers across the Netherlands will be analysed. The technical assessment will not only include the transport modes but all the system components required. Therefore, system boundaries specific to the energy carrier and the transport modes will be developed. All the system components will be modelled and the data required to model each component will be gathered before modelling. The energy requirements for each system component will be estimated resulting in the estimation of the energy efficiencies of each energy carrier in the different transport modes. The transport routes and the quantity of the energy carriers will also be decided and estimated in this step, which is further elaborated in chapter 7 under the relevant sections, pertaining to each energy carrier.

2.2.5 System costs

The system costs for each energy carrier in the various transport modes will be estimated in this step, by adding the individual component costs relevant to each transport mode. This would involve gathering data related to the costs of each system component from companies and literature. This step is further elaborated in chapter 8.

2.2.6 Estimation of region specific costs

The techno-economic analysis will estimate country specific costs for the energy carriers in the various transport modes. To understand whether these costs will vary across different regions in the Netherlands, it is necessary to estimate region specific costs. The estimation of region specific costs will be based on the system boundaries and the supply and demand of the energy carrier across the Netherlands.

2.2.7 Discussion of the results

A comparison among the energy efficiencies and the system costs of transporting each energy carrier in the different transport modes, will result in the identification of the most energy efficient and economical energy carrier and transport mode to satisfy the hydrogen demand in the Netherlands. Further, the breakdown of the results will indicate, the system components that have a major effect on the system costs for each energy carrier and the respective transport mode. Identifying these factors and performing a sensitivity analysis will give an indication into what affects these factors and finally result in the identification of the bottlenecks in the transportation of hydrogen and hydrogen energy carriers.

3 Energy carriers

This chapter will first look into the possible hydrogen energy carriers and the shortlisting process of the energy carriers followed by a detailed description of the chosen energy carriers.

3.1 List of energy carriers

Aakko-saksa et.al, states many hydrogen energy carriers as possible alternatives to hydrogen but all of these energy carriers cannot be researched as doing so would require a considerable amount of time (Aakko-saksa et al., 2018). Hydrogen energy carriers in this thesis is defined as renewably produced energy carriers that transport the hydrogen molecule for the purpose of energy generation. This alongside multiple papers mentioned in chapter 1 were used as a source to shortlist possible energy carriers and further elimination was done using three criteria; Maturity of the energy carrier, Data availability for the energy carrier and knowledge available to handle and transport the energy carrier. Table 1, shows the energy carriers considered and the how the screening took place using the three criteria mentioned earlier.

Table 1: Shortlisting and elimination of the hydrogen energy carriers

Energy carriers	**Maturity of carrier**	**Data availability**	**Knowledge available to handle and transport**	
Hydrogen	Yes	Yes	Yes	Y
Ammonia	Yes	Yes	Yes	Y
Synthetic methane	Yes	Yes	Yes	Y
Methanol	Yes	Yes	Yes	Y
Dibenzyl toluene (LOHC)	Yes	Yes	Yes	Y
Toluene (LOHC)	Yes	No	Yes	N
Dimethyl ether	Yes	Yes	Yes	Y
Polyoxymethylene dimethyl ethers	Yes	No	No	N
Formic acid	Yes	Yes	Yes	Y
$NaBH_4$	Yes	No	No	N

For the criteria - maturity of the energy carrier, 'Yes' would mean that the energy carrier is mature and is manufactured and utilised on a large scale while 'No' reflects that the product is used in a small scale, ex. in a pilot or in labs. For the criteria - data availability, 'Yes' would mean that data is readily available for that energy carrier through literature or from companies and 'No' would mean that data is not easily accessible. For the criteria - knowledge available to handle and transport the energy carrier, 'Yes' reflects that there is multiple literature having assessed the multiple transport modes or companies have the knowledge on transporting them.

From table 1, nine hydrogen energy carriers other than hydrogen have been selected for screening from literature as possible alternatives to hydrogen. Through elimination of the energy carriers by using the three criteria, six energy carriers other than hydrogen have been shortlisted. Benzyl toulene, oxymethyl ether and $NaBH_4$ was eliminated as a result of the screening. For the thesis, it was decided to analyse five energy carriers including hydrogen, therefore it was decided to eliminate two more energy carriers. The elimination was done by considering the number of hydrogen molecules that each energy carrier has. As a result of this, formic acid and dibenzyl toulene was eliminated as formic acid carried the least amount of hydrogen molecules in its chemical structure and dibenzyl toulene did not carry any hydrogen molecule but has to be hydrogenated to transport the hydorgen molecule and dehydrogenated to release the molecule.

3.2 Description of the selected energy carriers

3.2.1 Hydrogen

Hydrogen is an energy carrier that is found abundantly in nature as a compound bonded with other elements (IEA, 2015). A carbon free energy carrier with a high gravimetric energy density was a major factor that put hydrogen in the spot light as a potential fuel source for the future (Chiesa, Lozza, & Mazzocchi, 2005)(Singh et al., 2015). Apart from being a potential fuel, hydrogen is also looked into as a potential energy storage medium (IEA, 2015). The large scale integration of renewable energy systems (RES) in the grid has caused imbalances in the supply and demand for electricity, resulting in stressed electricity grids (Ajanovic & Haas, 2018). As a consequence, a need for a energy storage system was created to store excess electricity in times of over production/supply. In this respect, hydrogen can be produced from the excess/surplus electricity and be stored over long periods of time without degrading or losing energy potential over time (IEA, 2019). The improvements in hydrogen fuel cell technology have also pushed for hydrogen to be introduced in transport markets, as the transport industry is pushing to decarbonise the sector (IEA, 2015). Since hydrogen exists as a compound on earth, hydrogen can only be produced through different processes (Navigant, 2019). To produce hydrogen in a renewable manner (green hydrogen), an electrolyser will have to be used to split water molecules into hydrogen and oxygen atoms (Navigant, 2019).

3.2.2 Ammonia

Ammonia is one of the most widely used chemicals world-wide, which serves as an input for the synthesis of fertilisers and also for cleaning products in smaller quantities (Aakko-saksa et al., 2018). Global food demand relies heavily on fertiliser production, thereby making ammonia an important chemical for food security. Similar to hydrogen, ammonia is a carbon free energy carrier with only nitrogen and hydrogen atoms in its chemical structure (Bartels, 2008). As a hydrogen energy carrier, ammonia has the potential to replace hydrogen, as it enables transport and storage in liquid form at lower pressures and higher temperatures relative to hydrogen (Lamb et al., 2019). Ammonia can be easily produced from hydrogen and nitrogen using the haber-bosch process (Aakko-saksa et al., 2018).

3.2.3 Methanol

Methanol is a chemical that is widely used in labs and serves as a chemical feedstock to various types of industries. It is an organic liquid that is flammable and toxic in nature, which makes handling methanol complex (Methanol Institute, 2013). Despite this, methanol is being trade globally, with methanol industries usually located in areas rich in natural gas (Methanol Institute, 2013). As a hydrogen energy carrier, methanol has a high hydrogen content of 12.5% and can be easily transported as it is a liquid at ambient conditions unlike hydrogen (Aakko-saksa et al., 2018). Methanol is currently being produced from synthesis gas but can be produced renewably from recycled CO_2 and hydrogen from the electrolysis of water (Aakko-saksa et al., 2018)(Olah A., 2009).

3.2.4 Dimethyl ether (DME)

DME is a derivative of methanol which has similar performance characteristics to diesel but is stored and transported like Liquefied Petroleum Gas (LPG) (ETIP Bioenergy, n.d.). DME's diesel like performance has enabled it to be used as a substitute for diesel in diesel engines, in some countries (Anon, 2011). The degradable nature of DME in the atmosphere, its non-toxic characteristic and LPG-like properties makes DME a suitable hydrogen energy carrier that can be transported over long distances (ETIP Bioenergy, n.d.). DME is currently produced by the methanol dehydration process but can also be produced in a renewable manner from recycled CO_2 and hydrogen from the electrolysis of water (Kiss, Suszwalak, & Ignat, 2013)(Olah A., 2009).

3.2.5 Synthetic Methane

Natural gas is composed of 90 - 95% methane, which makes methane a widely used energy carrier for energy generation and as feedstock for industries (Dobrota, Lalić, & Komar, 2013). Due to the high methane content in natural gas, the properties and characteristics of methane are similar to that of natural gas. Therefore handling and transporting methane can be done using the existing natural gas infrastructure without much modifications. Synthetic methane has a one of the highest hydrogen content in a hydrogen energy carrier of 25% and is currently a major source for hydrogen production through the steam reforming of natural gas (Aakko-saksa et al., 2018). These advantages of a high hydrogen content and the ability to utilise existing infrastructure and knowledge of steam reforming makes synthetic methane a competitive hydrogen energy carrier. Synthetic methane can be produced in a renewable manner from hydrogen and carbon dioxide by a process called methanasation. Methanasation takes place at an industrial scale as catalytic methanasation which is a thermochemical process while biological methanisation is also a possible route to produce synthetic methane, which employs micro-organisms in an aqueous solution (Agora Verkehrswende and Frontier Economics, 2018).

4 System boundaries

This chapter will first discuss how the hydrogen demand and supply will be spread across the Netherlands. This will then be followed by the general system boundaries followed by the detailed system boundaries.

4.1 Supply and demand locations for hydrogen

The system boundary for this thesis will encompass system components beginning from the generation of the energy carrier to the storage and processing of the energy carrier at the destination. To be able to decide the system boundary, the supply and demand points for hydrogen across the Netherlands has to first be fixed. The Gasunie 2050 survey reports that hydrogen will be needed for transport, housing, industry and power generation in plants (Gasunie, 2018). The report further mentions that hydrogen will primarily be used for industrial use and power generation (Gasunie, 2018). Therefore, the focus of the transport of hydrogen will be to the key industrial areas in the Netherlands. The Netherlands has 6 industrial clusters in and around the following areas: Delfzijl, Chemelot, Zeeland, Amsterdam, Emmen and Rotterdam (Ecofys, 2018). Thereby these six locations will serve as points of demand for hydrogen in the future. With the demand fixed, the supply points of hydrogen has to be decided.

Currently, most of the energy carriers that have been discussed in section 3.2 are produced in the Netherlands. Akzonobel in Europoort at Rotterdam is the only manufacturer of DME in the Netherlands, with an annual production of 45 ktons (Nouryon, n.d.). Methanol is currently produced by BioMCN in Delfzijl with a production rate of 870 ktons per yer (OCI, n.d.). Another proposed project in Rotterdam by Emerken will have a methanol production rate of 200 ktons per year (Karidis, 2018). Ammonia is currently produced by Yara in Zeeland and OCI Nitrogen in Geleen with a production capacity of 1500 ktons per year and 1130 ktons per year, respectively (OCI NITROGEN, n.d.)(Brown, 2019). For synthetic methane, there are currently no production facilities in the Netherlands, but many pilots have started off in different parts of Europe (Audi MediaCenter, n.d.)(Lampinen, 2012). LOHC is relatively new compared to the other energy carriers and is currently only produced in Germany (https://www.hydrogenious.net/index.php/en/hydrogen-2-2/) and Japan (https://www.chiyodacorp.com/en/service/spera-hydrogen/).

As of today, no large scale hydrogen electrolysers exist in the Netherlands but there are plans announced publicly for hydrogen electrolysers in IJmuiden by Nouryon, in the northern part of Netherlands by Gasunie and also in Rotterdam by the port of Rotterdam (Nouryon, 2018)(Van Roy, 2018)(World Energy Council, 2017). In the Infrastructure Outlook 2050 report by Tennet and Gasunie, a proposed hydrogen grid has been shown with probable locations of hydrogen electrolysers (Tennet & Gasunie, 2018). In the same report, the authors modeled multiple scenarios where hydrogen electrolysers are located in the six industrial clusters and other areas, but the size of the electrolysers were not mentioned or quantified (Tennet & Gasunie, 2018). The Hydrogen - Industry as a catalyst report by the World Energy Council - Netherlands, states that hydrogen electrolysers will be found in areas which are connected to offshore wind farms (World Energy Council, 2019). This would most likely be in the areas of Rotterdam, Amsterdam, Zeeland and Delfzijl, which are either partners in the North Sea wind farm project or are probable locations for the landing of the cables coming in from the North Sea wind farms (Port of Rotterdam, n.d.)(Zeeland seaports, n.d.)(van Wijk, 2018). This coincides with the Gasunie 2050 survey report mentioned earlier, where it is expected that the North Sea wind farms will power the hydrogen electrolysers (Gasunie, 2018).

The industrial clusters of Chemelot and Emmen have no connections to the offshore wind farms as they are further inland and not along the coasts. For the industrial cluster in Emmen, since it currently does not produce any of the energy carriers or would it be possible for it to be considered as a landing area for cables from the offshore wind farms, an electrolyser there can be ruled out. In the case of Chemelot which currently has an ammonia plant run by OCI Nitrogen, it can be considered as a potential location for a hydrogen electrolyser as well. Despite its potential to have a hydrogen electrolyser, it should be taken into account that hydrogen electrolysers themselves have been based on the surplus electricity generated from the offshore wind farms. Therefore, it becomes relatively difficult to have extra electricity cables coming in from the onshore connections of the export cables, to the Chemelot industrial cluster. This would mean more electricity losses and additional infrastructure will be needed to support an electrolyser in Chemelot. To have a fair comparison among the energy carriers and complex nature of including Chemelot in this thesis, it is assumed that there will not be hydrogen electrolysers in Chemelot. Therefore, hydrogen will be transported by pipeline or road to Chemelot from one of the other clusters producing hydrogen. This leaves us with hydrogen electrolysers in the industrial clusters in Rotterdam, Zeeland, Amsterdam and Delfzijl which is assumed to be powered by North Sea offshore wind farms. Figure 2 shows the six industrial clusters and the four clusters along the coast which will have hydrogen electrolyers powered by offshore wind farms.

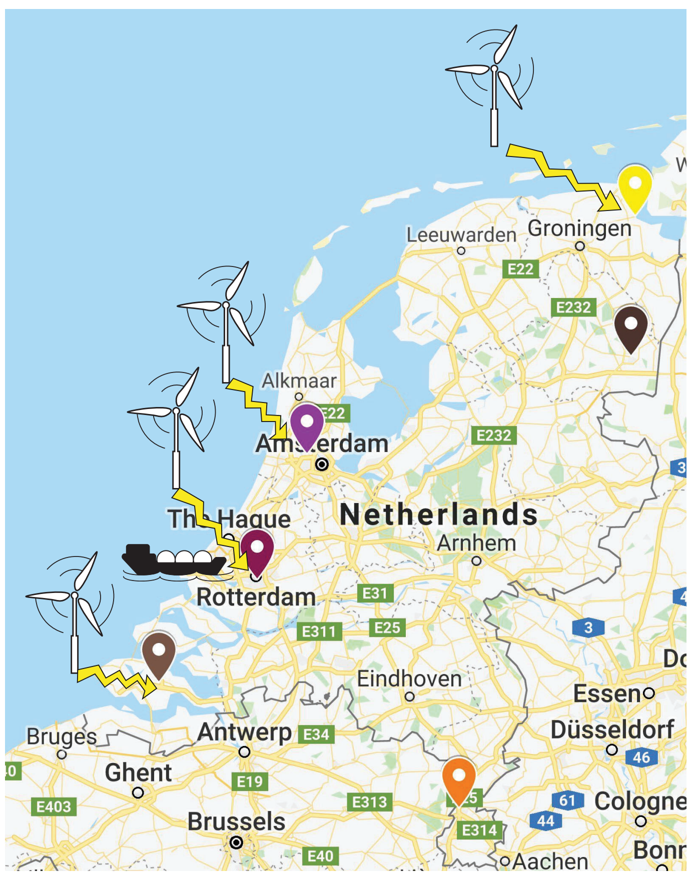

Figure 2: Industrial clusters in the Netherlands

With both the supply and demand points located, the imbalance of the supply and demand across the Netherlands will be the driver for the transportation of the energy carriers across the Netherlands. In the case, that the supply will not be able to fulfill the demand, the energy carriers will have to be imported from other countries. The import of energy carriers are expected to be through maritime shipping that would enter one of the many ports in the Netherlands. The Netherlands have four seaports that can handle liquid and gas products which are: Rotterdam, Amsterdam, Delfzijl and Zeeland. Rotterdam is the biggest of the four ports and also the largest port in Europe with the infrastructure to handle large quantities of any type of imports. Therefore, Rotterdam is assumed to be the port where the imports will be coming into and therefore the import point will merge with the existing supply point of hydrogen at Rotterdam.

4.2 General system boundary

Figure 2 gives a good picture of the whole system but does not represent the exact system boundary of this thesis. The transport of energy carriers would not only require transporting the energy carriers from source to destination but would also include the production, processing and storage of the energy carrier for it to be transported. An example would be the transport of liquid synthetic methane by road. Synthetic methane has to be liquefied at the source to be able to transport it using LNG road tankers and then regasified at the destination to be utilised. Therefore the system boundary will include the production of synthetic methane, liquefaction and storage of synthetic methane at the source, loaded onto and transported by road tankers and then unloaded, stored and regasified at the destination. Synthetic methane can either be utilised directly or reformed to produce hydrogen, if hydrogen is needed. In the case that hydrogen is required as a feedstock for industries or for non-energy purposes, synthetic methane reformers would become a part of the system boundary as well. In contrast, the system boundary for the pipeline transport of hydrogen would require the production of hydrogen and storage at the source, compression of hydrogen for pipeline transport followed by decompression and storage of hydrogen at the destination. Both systems highlight the variation of the system components and thereby indicates the need for a fair and comparable system boundary. The processing of the energy carrier will differ depending on the energy carrier and the transport mode used. Therefore, the system boundaries should take into account the processing required for the energy carrier to make sure there is a valid comparison between the energy carriers in the various transport modes. The general system boundaries can be seen in figure 3 isolated by the dotted lines from the rest of the system.

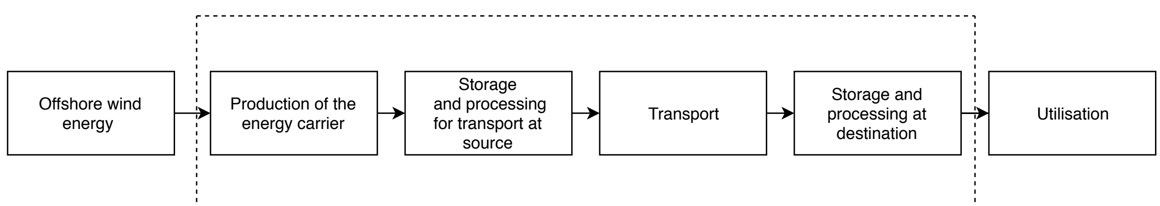

Figure 3: System boundary

As seen in figure 3, the system boundary extends from the production of the energy carrier to the storage and processing of the energy carrier at the destination. The offshore wind energy component is not included in the system boundary as the wind farms are not modelled but rather is only seen as an electricity input for the system. Therefore only the power available from the wind farms and the selling price of electricity will be taken into account. Utilisation of the energy carrier is also not modelled in this thesis and therefore not included in the system boundary.

4.3 Detailed system boundaries

Pipeline and road transport are both land based transportation modes which will transport the energy carrier from supply points to demand points in the Netherlands. Maritime shipping on the other hand, a sea based transport mode, will not directly transport the energy carrier to the demand points. It will rather supply the shortage of the energy carrier faced in the Netherlands through the port of Rotterdam to be further transported on land by pipeline or road transport. This would lead to the inclusion of shipping or the import of the energy carrier to become a part of the general system boundaries for road and pipeline transport. A more detailed system boundary can be seen in figure 4. The dotted lines represent the borders of the Netherlands.

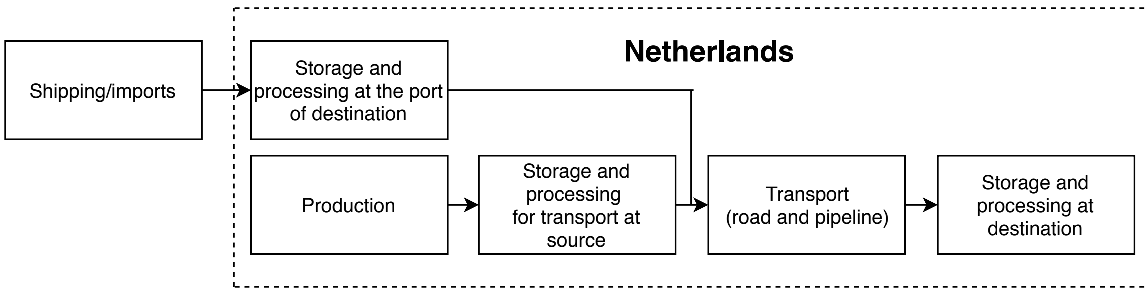

Figure 4: Detailed system boundary

As seen in figure 4, the system costs of road and pipeline transport of the energy carriers in the Netherlands will also include the system costs of shipping or importing the energy carrier. Therefore, there cannot be a comparison of maritime shipping with the land based transportation modes. The only comparison that can be made is among pipeline and road transportation. The cost of transporting the energy carrier by pipeline versus how much it would cost to do the same by road transportation will be focused on in this thesis while the effect of maritime shipping on the final system costs will be analysed.

5 Hydrogen demand in the Netherlands

This chapter will start first with the discussion of the demand for hydrogen at 2050 and then will further focus on how the demand for hydrogen would be distributed across the Netherlands.

5.1 Hydrogen demand at 2050

Multiple reports have laid out roadmaps for the Netherlands with the hydrogen economy being one of the many solutions, while some reports have been published specifically for transitioning to the hydrogen economy. A report from The Northern Netherlands Innovation Board (NIB) estimates that by 2030 that there will be a demand for 270 ktons of hydrogen while the Gasunie 2050 survey estimates that 444PJ of hydrogen would be required in the Netherlands for the year 2050 (van Wijk, 2018)(Gasunie, 2018). Since this thesis is based on transporting hydrogen and hydrogen energy carriers for the year 2050, the Gasunie forecast of 444PJ was used as the forecasted hydrogen demand for 2050 in this thesis .

The Gasunie report estimates are based on the reduction in emissions by 95% as per the target set out by the Dutch government for 2050 (Gasunie, 2018). Some of the ideas discussed in the report to achieve this target includes a larger share of renewable energy in the energy mix, carbon capture and storage (CCS) for the industrial sector, energy efficient buildings, geothermal heat as a heating source, heat pumps being implemented in industries, biomass to green gas and the use of hydrogen (Gasunie, 2018). As discussed in section 4.1, the Gasunie report also states how the 444PJ of hydrogen will be used in the Netherlands, which includes hydrogen needed for transport, housing, industry and power generation in plants. Hydrogen will primarily be used for industrial use and power generation which adds up to 380PJ (Gasunie, 2018). For this thesis, the Gasunie 2050 report is taken as the baseline scenario for the hydrogen demand, and this results in a demand of 444PJ of hydrogen needed by 2050. For reference, 444 PJ requires 3155 ktons of hydrogen using an energy density of 141 MJ/kg.

5.2 Distribution of energy among the industrial clusters

As mentioned in section 4.1, the Netherlands has 6 industrial clusters in and around the following areas: Delfzijl, Chemelot, Zeeland, Amsterdam, Emmen and Rotterdam (Ecofys, 2018). Despite the industrial clusters being well spread across the country, most of the industries are established in the southern part of the Netherlands, mostly near the port city of Rotterdam. Therefore, the size of the industrial clusters vary across the Netherlands. Thereby, it is necessary to map the energy demand per industrial cluster since each industrial cluster would require different amounts of hydrogen due to the varying sizes.

To allocate the hydrogen demand across the industrial clusters, it was necessary to find the energy demands of the industrial clusters. In many reports and roadmaps for example 'Transition to sustainable energy' by the Ministry of Economic Affairs or the 'Chemistry for Climate: Acting on the need for speed' by Ecofys, sector usage of energy in the Netherlands or the type of fuel used for energy production in industries are available but the energy usage per industrial cluster were unavailable (Ministry of Economic Affairs, 2016)(Ecofys, 2018). Eurostat, the European Union's statistics database and CBS, the Dutch statistics department, also do not provide the energy demands per industrial cluster. Specific reports from the industrial clusters, were more difficult to obtain except for the Rotterdam industrial cluster, for which some reports were available (Kreijkes, 2017)(Rotterdam-Moerdijk Industry Cluster work group, 2018). In the Three steps towards a sustainable industrial cluster report published by the Rotterdam-Moerdijk industrial cluster work group in 2018, it was reported that 260 PJ of energy is used for the production process in the industrial cluster, out of which half of the energy is provided by the waste gases from the refineries (Rotterdam-Moerdijk Industry Cluster work group, 2018). Another report Looking under the hood of the Dutch energy system published by CIEP in 2017, reports that the Rotterdam industrial cluster has a primary energy consumption of 201 PJ annually (Kreijkes, 2017). The other industrial clusters have actions plans and roadmaps, listing out tasks for CO_2 emission reduction but did not provide specific data on the energy consumption.

Multiple reports were available for the CO_2 emissions in the Netherlands. The Transitiepad Hoge Temperatuurwarmte report (VEMW, 2017), was the only one found that segregated CO_2 emissions cluster wise. The report states that the energy intensive industry or industries using high temperature heat, emitted 46 Mtons of CO_2 in 2016. The report further mentions that only 37 Mtons of CO_2 is a result of energy usage for heat and the rest 9 Mtons of CO_2 comes through emissions from fossil fuels used as feedstock. Out of the 46 Mtons, only 43 Mtons of CO_2 have been accounted for in this report. The table below shows the CO_2 emissions per industrial cluster as stated in the report. (VEMW, 2017)

Table 2: CO_2 emissions of the industrial clusters at 2016 (VEMW, 2017)

Industrial cluster	**Amount of CO_2 emitted yearly, Mtons**	**%**
Amsterdam	12	28
Chemelot	5	11
Delfzijl	1	2
Emmen	1	1
Rotterdam	17	40
Zeeland	8	19

CO_2 emissions from heat production can be seen as a direct function of energy usage but not CO_2 emissions from fossil fuels used as feedstock. Since the report accounts for only 43 Mtons of CO_2 emissions and, the 9 Mtons of CO_2 emissions from use as feedstock mentioned earlier is not specific to any industry or industrial cluster, 43 Mtons of CO_2 emissions can be used in the thesis as a function of energy demand.

Nevertheless, some industries like ammonia plants are usually interconnected to other plants that use ammonia as a feedstock like urea and ammonia nitrate plants (Fossum, 2014). In the case of urea, CO_2 emissions are also used as an input and thereby a part of the CO_2 emissions from ammonia plants are directed to the urea plants while only some are emitted to the atmosphere (Fossum, 2014). Thereby, it was necessary to correct the values above for carbon emissions from ammonia plants. In the Netherlands, two ammonia plants exist: one by Yara in Zeeland and one by OCI nitrogen in Chemelot, which has a capacity of 1500 ktons and 1130 ktons per annum respectively (Brown, 2019)(OCI NITROGEN, n.d.). Assuming that both the plants are using the Best Available Technology (BAT), both plants should have an energy efficiency value of 31.8 GJ/ton NH_3 (Fossum, 2014). Since natural gas is the main energy source in the Netherlands, it is assumed that the natural gas is also used in the ammonia plants as an energy source, which has a carbon dioxide emission factor of 56.1 $kgCO_2/GJ$ (Fossum, 2014). This gives a value of 2.7 Mtons of CO_2 of emissions from Yara in Zeeland and 2.0 Mtons of CO_2 of emissions from OCI Nitrogen in Chemelot. These values are then added to the existing values, which can be seen in table 3.

Table 3: Updated CO_2 emissions of the industrial clusters at 2016

Industrial cluster	**Amount of CO_2 emitted yearly, Mtons**	%
Amsterdam	12	25
Chemelot	7	14
Delfzijl	1	2
Emmen	1	1
Rotterdam	17	36
Zeeland	11	22

Therefore the cluster wise hydrogen demand allocation for the year 2050 was based on the updated cluster wise CO_2 emissions during the year 2016 which is shown in table 3. Table 4 shows the hydrogen demand in PJ and the respective demand in kilo tons of hydrogen required for each industrial cluster. It can be noticed that the hydrogen demand is the highest in Rotterdam followed by Amsterdam and Zeeland, while Delzijl and Emmen have the lowest demand for hydrogen.

Table 4: Hydrogen demand predicted for the industrial clusters at the year 2050

Industrial cluster	%	**Hydrogen, PJ**	**Hydrogen, ktons**
Rotterdam	36	159	1130
Amsterdam	25	113	802
Zeeland	22	100	708
Chemelot	14	61	434
Delfzijl	2	7	47
Emmen	1	5	33

The reason to use CO_2 emissions of the industrial clusters for the year 2016 and relating that directly to the energy demand at 2050 was due to the reasons of unavailability of data on the energy demands of the industrial clusters and the difficulty to predict the growth of the industrial clusters. It is possible that the there maybe unreported CO_2 emissions in the report used but it is expected that plants are to become more energy efficient in the future and thereby an reduction in energy consumption is expected in the future (Ecofys, 2018). Another possibility is the change in the dynamics of the growth of the industrial clusters; smaller clusters may become more dominant in the future and thereby the demand for energy may shift from dominant industrial clusters like Rotterdam to Amsterdam. There is much variability in what could be the actual energy demand at 2050 but for this thesis, it is assumed that the cluster wise CO_2 emissions shown in table 3 for the year 2016 will represent the cluster wise energy demand for the year 2050.

6 Hydrogen production capability across the Netherlands

This chapter will first discuss where the power for the electrolyser will be coming from followed by estimating the amount of power available for each industrial cluster to produce hydrogen.

6.1 Power available to produce hydrogen

As discussed in section 4.1, it is assumed that there will be hydrogen electrolysers present in the industrial clusters of Rotterdam, Amsterdam, Delfzijl and Zeeland. It is also assumed that the hydrogen electrolysers would be powered by electricity coming in from the offshore wind farms. The Gasunie 2050 survey report states that hydrogen electrolysers would be powered by surplus power and also by residual electricity [1] (Gasunie, 2018). Multiple reports mentioned in section 1.2 have discussed on how surplus electricity would be used for hydrogen electrolsyers but no other report has explicitly mentioned the use of residual electricity for hydrogen production other than the Gasunie report (Gasunie, 2018). Therefore, it is assumed that the hydrogen electrolysers would be powered only by offshore wind energy and not residual electricity. If there is a shortage in the supply of hydrogen, it is expected that the shortage would be satisfied through imports by maritime shipping via the port of Rotterdam. The next step would be, to look at the offshore wind farms that would develop in the North Sea by 2050. Till date, concrete plans for offshore wind farms have only been made till the year 2030 by the Dutch government (RVO, n.d.). It is expected to have a total capacity of 11 GW by 2030 including existing wind farms (RVO, n.d.). Multiple reports have made forecasts as well, the Gasunie report predicts 55 GW of offshore wind farms to be operational by 2050 while a PBL report considers four scenarios with the most sustainable scenario predicting a capacity of 60 GW by 2050 (Gasunie, 2018)(Matthijsen, Dammers, & Elzenga, 2017). The breakdown of existing projects and projects planned till 2030 can be seen in table 5 and 6 respectively.

Table 5: Existing offshore wind farms in the Netherlands (RVO, n.d.)

Existing wind farms	**Capacity, MW**	**Connections**
Luchterduinen	129	In the area of Amsterdam
Egmond aan Zee	108	In the area of Amsterdam
Princess Amelia	120	In the area of Amsterdam
Gemini	600	In the area of Delfzijl

Table 6: Expected offshore wind farms in the Netherlands by 2030 (RVO, n.d.)

Upcoming wind farms	**Capacity, MW**	**Connections**
Borselle	1380	In the area of Zeeland
Hollandse Kust (South)	1440	In the area of Rotterdam
Hollandse Kust (North)	700	In the area of Amsterdam
Hollandse Kust (West)	1400	In the area of Amsterdam
Ten Noorden van de Waddeneilanden	700	In the area of Delfzijl
IJmuiden Ver	4000	In the area of Amsterdam and Rotterdam

[1] Residual electricity refers to the temporary surplus available in the electricity market

Despite the high amounts of installed capacity of offshore wind farms predicted, only the surplus electricity would be available for the hydrogen electrolysers. The priority of renewable offshore wind energy generation is to reduce dependence on the current use of fossil fuels for electricity generation and thereby only the surplus will be used for hydrogen generation. The Gasunie 2050 survey report predicts that 15 GW of surplus offshore wind energy would be available for hydrogen production by 2050 while the PBL report only predicts the total capacity of offshore wind farms by 2050 (Gasunie, 2018)(Matthijsen et al., 2017). Even with the prediction of 15 GW of excess electricity, this value is assumed for the whole of Netherlands and not for specific areas in the Netherlands. Therefore, it was decided to assume the same distribution of offshore wind farm connections in 2030 for 2050 as well. Further, it is also assumed that the total offshore wind farm capacity would be 55 GW with a dedicated surplus of 15 GW for hydrogen production for the year 2050. Table 7 shows the expected total and surplus capacities for the four areas that would likely be connected to offshore wind farms.

Table 7: Power available for the hydrogen electrolysers

Area	**Capacity at 2030, MW**	**%**	**Capacity at 2050, MW**	**Surplus capacity at 2050, MW**
Rotterdam	4107	39	21356	5824
Amsterdam	3790	36	19708	5375
Delfzijl	1300	12	6760	1844
Zeeland	1380	13	7176	1957
Total	10577	100	55000	15000

In the specific case of IJmuiden Ver, there are connections to both Amsterdam and Rotterdam onland but capacities of how much of power is exported to each area is not explicitly mentioned (Kroon, 2018). The only information that has been made available is that IJmuiden Ver is expected to have three export cables, of which one will go into the region of Amsterdam and the other two to the area of Rotterdam (Kroon, 2018). Since, capacities have not been specified of how much of electricity will be exported through each cable, based on the number of cables coming onshore, it is assumed that $\frac{2}{3}$rd of the power is exported to Rotterdam while $\frac{1}{3}$rd of the power is exported to Amsterdam.

Since offshore wind farms are located far from the coast, it is necessary to account for the electricity losses when transmitting from the offshore wind farms to the onland connections. The losses include cable losses and converter losses, which on average till a distance of 150 km are limited to 5% for High Voltage Direct Current (HVDC) lines (Papadopoulos et al., 2015). HVDC cables have lower cable losses over longer distances compared to High Voltage Alternative Current (HVAC) cables and have replaced HVAC cables for connections to offhsore wind farms (Papadopoulos et al., 2015). Using this estimate of 5%, the power available for hydrogen electrolysers is shown in table 8.

Table 8: Power available after transmission losses

Industrial cluster	**Surplus offshore, MW**	**Onshore, MW**
Rotterdam	5824.	5533
Amsterdam	5375	5106
Delfzijl	1844	1751
Zeeland	1957	1859

7 Technical analysis

This chapter will first discuss in detail the transport modes for transporting the energy carriers and then will be followed by a detailed discussion of the technical requirements for each energy carrier.

7.1 Transport modes

7.1.1 Road transport

Energy carriers can be transport by road transport in a multiple number of ways. For gaseous energy carriers, tube trailers are the most common mode of road transport (US DRIVE, 2013). Tube trailers consists of multiple horizontal tubes on trailers, in which the gas is loaded into and then transported to the destination. The number of tubes that can be transported by trucks usually vary from 6 - 60 tubes. Tube trailers usually operate at 250 bar but new ones have been certified to operate at 500 bar (Linde, n.d.). Liquid energy carriers can be transported by road tankers. Road tankers are insulated steel vessels usually at atmospheric pressure, which can also handle liquids at cryogenic temperatures. Due to the variations of trucks and the capacities that each truck can transport, regulations exist to limit the amount of payload that can be transported by a single vehicle on road. Road transport in the European Union is limited to 44 tons that can be carried by a two - three axle trailer on the road (Council of the European Union, 2015). This limits the capacity of hydrogen and any other product that can be transported by road. Regulations also limit the speed of the vehicle to 50 km/h in urban areas (Council of the European Union, 2015), thereby 50 km/h was taken as the average speed of the vehicles on road for this study.

7.1.2 Maritime shipping

Maritime shipping of the energy carriers and other fluid chemicals are usually done in their liquid form. In the case of energy carriers that are a gas at atmospheric conditions, the energy carriers are cooled down to bring them to a liquid state. Compressed forms of gases have been shipped in the past but as of today, compressed marine carriers do not exist (Babilis, 2018). Eventhough multiple projects have seem to be promising on paper, none of them have been commercialised or brought into operation (Tractebel Engineering, 2015). Thereby, gases are usually transported as a liquid even at cryogenic temperatures, for example: Liquid Natural Gas (LNG). In the case of energy carriers that are already in their liquid state at atmospheric conditions, normal steel tankers are used with no additional need to liquefy them.

7.1.3 Pipeline

Pipeline are used for transporting large quantities of gases and liquids over long distances where road transport is not economical (Sashi Menon, 2005). Designing a pipeline is a complex process as the cost of a pipelines heavily depends on the steel grade used and diameter of the pipe which further determines the compressor or pump capacity needed. A compressor or pump is used in a pipeline, to provide the necessary kinetic energy, for the fluid to flow through the pipeline. The process of designing a pipeline is shown in the flowchart below. The process varies in terms of the equations used, depending on whether a liquid or gas flows through the pipe. The flowchart describes the process to design the pipeline, by comparing the costs of using various steel grades and their respective diameters for the same flow rate. It is assumed that the pipelines are point to point with no elevations in a straight line configuration, which means that the terrain is flat and there will be no bends in the pipeline. The pipeline design approach was adopted from multiple books (Sashi Menon, 2005)(Mohitpur, M Goslan, & H Murray, 2000)(Knoppe, 2015).

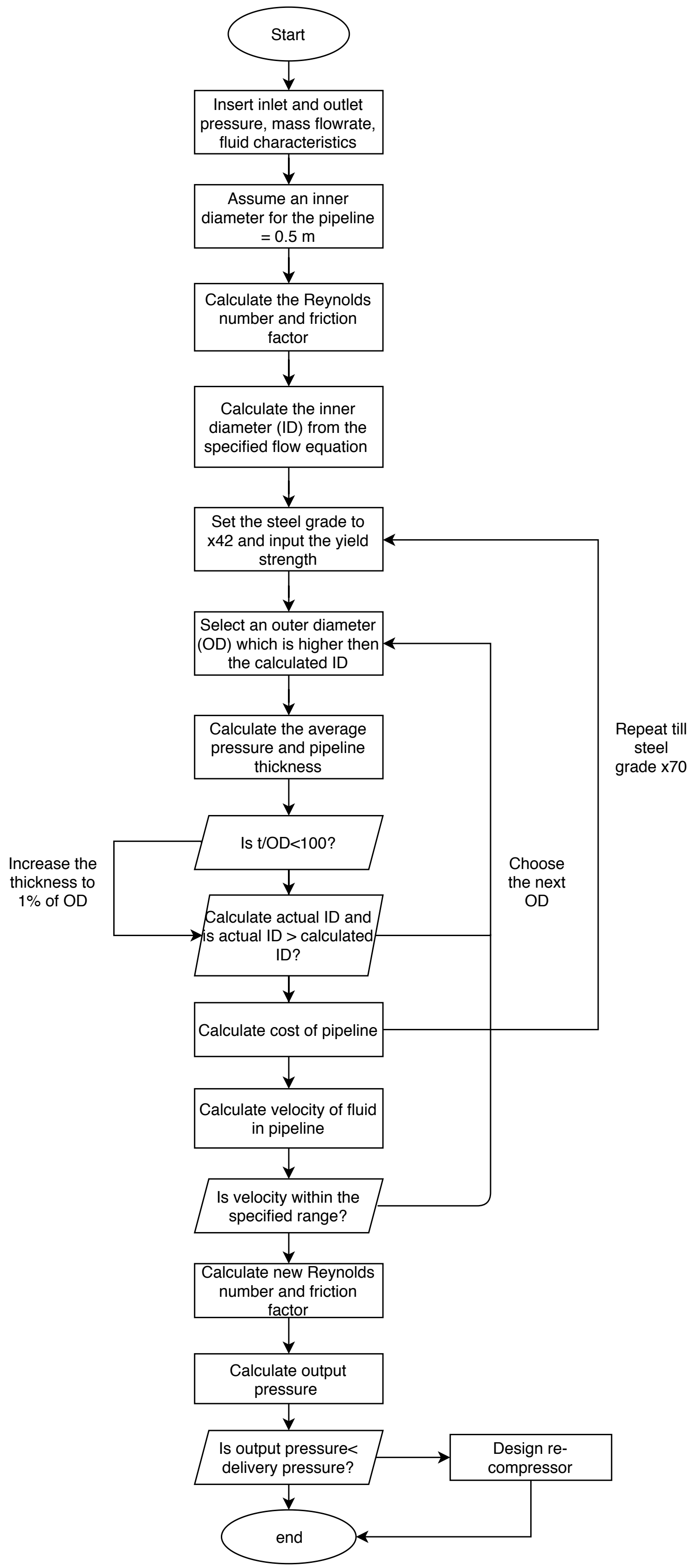

Figure 5: Pipeline design flowchart adapted from costs, safety and uncertainties of CO_2 infrastructure development (Knoppe, 2015)

As mentioned earlier, one of the main elements of designing the pipeline is to choose the correct the diameter of the pipe. To calculate the diameter of the pipe, the Reynolds number and the Darcy friction factor have to first be calculated. The formula used to calculate the Reynolds number is given below (Sashi Menon, 2005).

$$R = 0.5134 * \frac{P_b * G * Q}{T_b * v * d_{in}} \tag{1}$$

where, P_b is the base pressure in kPa, T_b is the base temperature in Kelvin, G is the gas gravity [2], Q is the mass flow rate of the fluid in the pipe in m^3/day and v is the viscosity of the fluid in Poise.

This is followed by the calculation of the Darcy friction factor, f. There are multiple methods of calculating the friction factor with multiple equations like Panhandle A, Panhandle B, AGA, Colebrook-white equation etc. which is used depending on the type of flow of the fluid (Sashi Menon, 2005). The Colebrook-white equation is an iterative method of calculating the friction factor which can be used for medium to high flowrates (Sashi Menon, 2005). The iterative method allows for a low error margin of the calculated value. Since high volumes of fluid would be transported across the Netherlands, the Colebrook-white equation is used. The equation is given below (Sashi Menon, 2005).

$$\frac{1}{\sqrt{f}} = -2 * log_{10} * (\frac{K}{3.7 * d_{in}} + \frac{2.51}{R * \sqrt{f}}) \tag{2}$$

where, K is the roughness factor.

With the Reynolds number and friction factor calculated, the actual inner diameter can then be calculated. The equation is shown below (Sashi Menon, 2005).

$$ID = (\frac{\frac{Q * f^{0.5} * P_b}{T_b * 77.54}}{(\frac{P_1^2 - P_2^2}{G * T_{ave} * Z_{ave} * l})^{0.5}})^{0.4} \tag{3}$$

where, Q is the mass flow rate in scf/d, P_b is the base pressure in psia, T_b is the base temperature in R, P_1 is the inlet pressure in psia, P_2 is the outlet pressure in psia, T_{ave} is the average temperature, Z_{ave} is the average compressibility factor. The calculated inner diameter is in inches.

For liquids, the calculation of the inner diameter varies with respect to the formula mentioned above. The design pressure drop in Pa/m is first calculated, which is then used to calculate the inner diameter required for the pipe (Knoppe, 2015). This is shown in the equations below.

$$P_{design} = \frac{P_1 - P_2}{l} + \frac{g * \rho}{l} \tag{4}$$

$$ID = (\frac{8 * f * Q}{\pi^2 * \rho * P_{design}})^{0.2} \tag{5}$$

where, Q is the mass flow rate in kg/s, l is the length of the pipeline in m, P_1 and P_2 is is the inlet and outlet pressures in Pa and ρ is the density of the liquid in kg/m^3.

Now that the inner diameter is calculated, the outer diameter of the pipe can be found. The outer diameter of pipes are usually standard and denoted as nominal pipe sizes (NPS). Therefore, the outer diameter is the next available size larger than the calculated inner diameter.

[2] Gas gravity is the molar mass of the gas divided by the molar mass of air

Next, the thickness of the pipe has to be calculated to determine whether the outer diameter of the pipe is sufficient. To calculate the thickness of the pipe, the steel grade has to be chosen, which indicates the yield strength of the pipe. The various steel grades can be seen in table 9.

Table 9: Steel grades and costs used for pipelines (Knoppe, 2015)

Steel grade	**Yield stress, Mpa**	**Costs, (€/kg)**
x42	275	1.17
x52	355	1.2
x65	460	1.37
x70	500	1.49
x80	550	1.51
x90	620	1.53
x100	690	1.54
x120	890	1.79

By selecting the steel grade, the corresponding yield stress can be used for calculating the thickness of the pipe. Average pressure of the fluid in the pipeline is also required to calculate the thickness of the pipe. The equation to calculate the average pressure is shown below (Sashi Menon, 2005).

$$P_{ave} = \frac{2}{3} * (P_1 + P_1 - \frac{P_1 * P_2}{P_1 + P_2}) \tag{6}$$

The equation to calculate the thickness of the pipe is given below (Sashi Menon, 2005).

$$t = \frac{P_{ave} * OD}{2 * Y_s * d_f} + CA \tag{7}$$

where, $\mathrm{P_{ave}}$ is the average pressure, $\mathrm{Y_s}$ is the yield stress of the steel grade, $\mathrm{d_f}$ is the design factor and CA is the corrosion allowance.

The design factor varies according to the route of the pipeline. A design factor of 0.72 is used if the pipeline passes through a sparsely populated area, but if it passes through an area with a dense population, a design factor of 0.5 is used (Sashi Menon, 2005). The calculated thickness of the pipe is also bound to a constraint, to ensure the wall is not very thin relative to the diameter of the pipeline. Therefore a maximum ratio constraint of OD/t of 100 is used as a check, to make sure that the thickness of the pipe suffices. This is then followed by calculating the actual inner diameter of the pipe (Knoppe, 2015).

$$ID = OD - (2 * t) \tag{8}$$

The inner diameter of the pipe, ID is then calculated by subtracting the wall thickness, t from the outer diameter, OD. This is then compared to the actual inner diameter calculated earlier on. If the calculated inner diameter is smaller than the actual inner diameter. then the pipe has to be re-sized or in other words, choose the next OD.

This is followed by calculating the cost of the pipeline which is done using the equation below (Knoppe, 2015).

$$Cost = \pi * t * (OD - t) * l * \rho_{steel} * C_{steel} \tag{9}$$

where, ρ_{steel} is the density of steel in $\mathrm{kg/m^3}$ and $\mathrm{C_{steel}}$ is the cost of the steel grade per kg which is given in table 9.

To avoid any damages to the pipeline and any vibrations to be induced in the pipeline when the fluid is flowing, the velocity of the liquids and gases and restricted. Therefore, the velocity has to be calculated using the equation below (Mohitpur et al., 2000).

$$v = \frac{4 * Q}{ID^2 * \pi * \rho} \tag{10}$$

where, Q is the mass flow rate in kg/s and the calculated velocity, v is in m/s. Liquids are restricted to a velocity of 0.8 - 6m/s while gases are restricted to 60m/s as per NORSOK standards, which are the standards used by the Norwegian petroleum industry (Knoppe, 2015). Petroleum companies like Shell have recommended gases to be limited to velocities between 5 - 20 m/s (Sashi Menon, 2005).

The final step, would then be to calculate the pressure drop at the end of the pipeline. The Reynolds number and friction factor can be calculated using the new inner diameter. The pressure drop can be calculated using the formula below (Sashi Menon, 2005).

$$P_{deli} = (P1^2 - [(\frac{Q * f^{0.5} * P_b}{T_b * 77.54 * ID^{2.5}})^2 * G * T_{ave} * Z_{ave}])^{0.5} \tag{11}$$

where, P_{deli} is the output pressure in psia. If the output pressure is less than the delivery pressure, P2 required then a re-compressor has to be designed.

For liquids, the pressure drop is first calculated in Pa/m, which is then used to calculate the delivery pressure. (Knoppe, 2015).

$$P_{drop} = \frac{8 * f * Q}{\pi^2 * \rho * ID^5} \tag{12}$$

$$P_{deli} = P_1 - (P_{drop} * l) \tag{13}$$

where, P_1 is in Pa and l is the length of the pipeline in m.

Pipeline transport unlike the other two transport modes have a fixed network and does not have flexible routes. Therefore, the pipeline network to transport the energy carriers should be fixed. Since the transport of the energy carriers was focused towards the industrial clusters, it would make sense to look at the high calorific natural gas pipeline network. This network, links all the industrial clusters and therefore will form a good baseline for a hydrogen energy carrier infrastructure. Figure 6 shows the current natural gas infrastructure and the red coloured lines reflect the high calorific network (Gasunie, 2004).

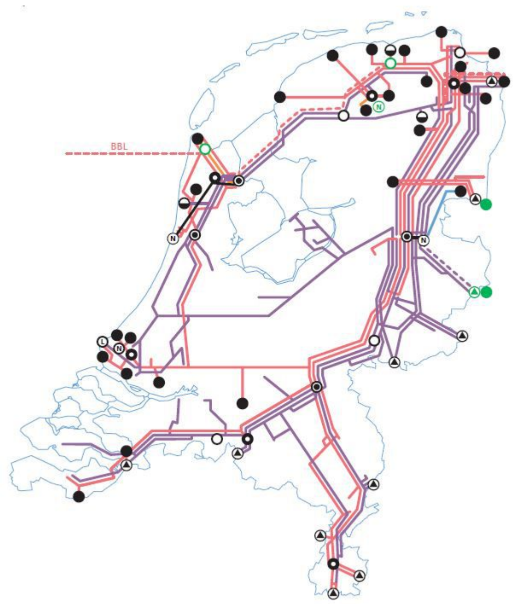

Figure 6: Natural gas infrastructure in the Netherlands (Gasunie, 2004)

As mentioned earlier, the report by Tennet and Gasunie also had a proposed hydrogen network which is shown in figure 7.

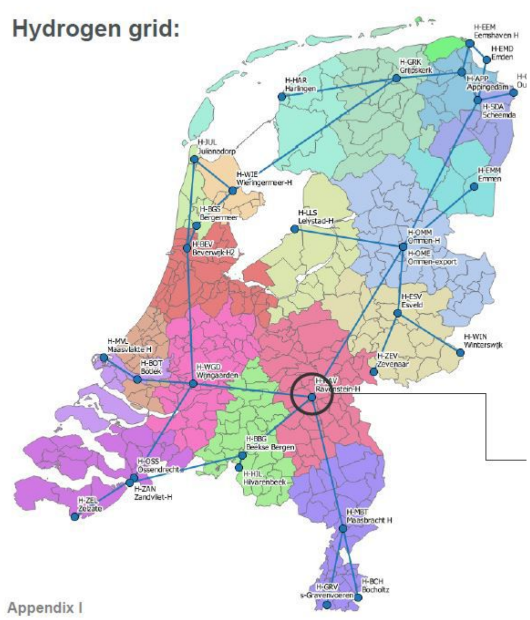

Figure 7: Proposed hydrogen grid (Tennet & Gasunie, 2018)

There are some noticeable differences between the networks. The main difference is the presence of a connection between Rotterdam and Zeeland in the proposed hydrogen network by Tennet and Gasunie, unlike the high calorific line which does not have this connection. In section 4.1, it was mentioned that the port of Rotterdam will serve as an import hub for all the energy carriers that come into the Netherlands and therefore the connection between Zeeland and Rotterdam becomes important. Therefore the hydrogen energy carrier infrastructure used for this thesis would include this connection. The final pipeline network used for this thesis uses the high calorific network as the base case with the addition of the Rotterdam - Zeeland line, which can be seen in figure 8.

Figure 8: Proposed hydrogen energy carrier pipeline network

7.1.4 Compressors and pumps

Gases that are transported in its compressed form by road and pipeline will require a compressor to compress the gas to the operating pressure of the tube trailer or the pipeline. Depending on the pressure required and the calculated compression ratio, the number of stages required for the compression can be calculated. The sum of the work done by each individual stage will amount to the total sum of work done by the compressor (Knoppe, 2015). The formula to calculate the compressor capacity is given below (Knoppe, 2015).

$$Power = Q * \sum_{n=1}^{no.of stages} \frac{Z * R * T * y}{M * \eta_{ise} * \eta_{mech} * (y-1)} * (\frac{P_{out}}{P_{in}})^{\frac{y-1}{y}} \tag{14}$$

where, Q is the mass flow rate in kg/s, Z is the compressibility of the gas, R is the gas constant, T is the average temperature of the gas in Kelvin, y is the specific heat of the gas, M is the molecular mass in kg/mol, η_{ise} is the isentropic efficiency of the compressor, η_{mech} is the mechanical efficiency of the compressor, P_{out} is the discharge pressure of the compressor and P_{in} is the suction pressure of the compressor.

To load and unload liquid energy carriers onto and from the transport mediums at the required transport pressures, pumps are required. Depending on the pressure and the flowrates, the capacities of the pumps vary. The following formula was used to determine the capacities of the pumps (Moran, 2016).

$$Power = \frac{Q * \rho_{hydrogen} * g * H}{3.6 * 10^6 * \eta_{pump}} \tag{15}$$

where, Q is the mass flow rate in m^3/hr, ρ is the density of the liquid in kg/m^3, g is the acceleration due to gravity m/s, H is the head in metres and η_{pumps} is the efficiency of the pump.

7.2 Hydrogen transport

7.2.1 Hydrogen electrolysers

Using the power exported onland as discussed in section 6.1, hydrogen electrolysers can be utilized to produce hydrogen from water. There are four types of hydrogen electrolysis that have been researched into; Alkaline electrolysis, Solid Oxide electrolysis, microbial electrolysis and Proton Exchange Membrane electrolysis (PEM) (Shiva Kumar & Himabindu, 2019). PEM and Alkaline electrolysers are the most commercialized electrolysers and have the high efficiencies[3] of 60 – 70% for alkaline electrolysers and 55 - 60% for PEM electrolysers (IEA, 2019).

Currently there are two leaders in the manufacturing of electrolysers; Nel and Hydrogenics. Nel has a long history of manufacturing electrolysers with the biggest being of 135 MW for Norsk Hydro in Norway while Hydrogenics is relatively a new player in the market with current designs based on 25 MW electrolysers (Nel, 2016) (Hydrogenics, n.d.). Some of the hydrogen electrolysers available from both these companies have been listed in table 10.

Table 10: Hydrogen electrolysers currently available in the market (Hydrogenics, n.d.)(Nel, 2016)(Nel, n.d.)

Company	**Model**	**Type of electrolyser**	**Power consumption, MW**	**Hydrogen production, Nm^3/hr**
Nel	A – 485	Alkaline	2.1	485
Nel	A – 3880	Alkaline	17.1	3880
Nel	C – 300	Alkaline	1.3	300
Hydrogenics	HySTAT – 100 - 10	Alkaline	0.5	100
Hydrogenics	HyLYZER – 5000 – 30	PEM	25	5000

From the table above, it can be noticed that alkaline electrolysers dominate the market, because of their well established technology compared to PEM electrolysers (Shiva Kumar & Himabindu, 2019). The main advantage of alkaline electrolysers, other than it being a well-established technology, is that it is relatively cheaper and has a slightly higher efficiency (Shiva Kumar & Himabindu, 2019)(IEA, 2019). The disadvantage of using an alkaline electrolyser is that it has limited current densities, operates at lower pressures and is not a dynamic system (Shiva Kumar & Himabindu, 2019). A system that is not dynamic does not adapt to intermittent[4] energy inputs and would need a constant energy supply. On the contrary, PEM electrolysers adapts well with an intermittent energy supply, thereby has a quicker response time (Shiva Kumar & Himabindu, 2019). It also has a higher hydrogen production rate and operates at higher current densities (Shiva Kumar & Himabindu,

[3] Efficiency here is refered to the energy efficiency of the hydrogen electrolyser. It is the ratio of the amount of hydrogen produced to the amount of electricity required for hydrogen production

[4] Intermittent means unstable and volatile

2019). O.Schmidt et.al, in his review paper suggests that PEM electrolysers will be favoured in the future (Schmidt et al., 2017). He supports his suggestion by further elaborating the fact that, PEM electrolysers have the capability of scaling up easily for large scale hydrogen production due to high current densities, and its irregular or intermittent operation capability, which makes it suitable to be paired with volatile renewable energy sources (Schmidt et al., 2017). Taking these characteristics into account and this being a case study for 2050, it is assumed that PEM electrolysers will be more suitable due to the higher integration of renewable energy into the grid and mass production alongside technical advances will reduce the costs of PEM electrolysers. Therefore, PEM electrolysers are chosen for hydrogen production and in specific the model HyLYZER - 5000 - 30 which has a capacity of 25MW is chosen. Table 11 shows the number of electrolysers required and the respective hydrogen production quantities for the respective industrial clusters. This estimate is being made based on the power available on land as discussed in chapter 6.

Table 11: Hydrogen production

Industrial cluster	**Power, MW**	**No. of electrolysers**	**Hydrogen production, tons/year**
Rotterdam	5533	222	651559
Amsterdam	5106	205	601665
Delfzijl	1751	71	208382
Zeeland	1859	75	220121

Hydrogen production is estimated, taking into account that the electrolysers will only operate at 80% of the time. This is assumed to account for the availability of surplus power from offshore wind farms, as power output from wind farms are volatile as a result of changing wind patterns. Therefore it is not expected that surplus power to be available 100% of the time. From table 11, it can be noticed that Rotterdam and Amsterdam have the highest hydrogen production quantities due to the higher amount of power available to both these clusters as compared to Delfzijl and Zeeland.

7.2.2 Hydrogen imports

Analysing the supply and demand for hydrogen which has been discussed in section 5.2, it can be easily noticed that an imbalance exists. Therefore, the imbalance would have to be covered through imports from abroad, to be able to satisfy the demand. Currently, 1682 ktons of hydrogen is produced in the Netherlands, which can provide 237 PJ of energy. This means that an additional 207 PJ of energy has to be imported from abroad on an annual basis, which translates to 1473013 tons of hydrogen. As discussed in section 4.1, Rotterdam is assumed to be the port where the imports will be coming into. Table 12 shows the amount of hydrogen produced and imported into the Netherlands.

Table 12: Hydrogen supply in the Netherlands for the year 2050

Industrial cluster	**Hydrogen production, tons/year**	**Hydrogen imports, tons/year**
Rotterdam	651559	1437013
Amsterdam	601665	
Delfzijl	208382	
Zeeland	220121	
Chemelot	0	
Emmen	0	
Total	1681737	1437013

The production in the Netherlands and the imports both add to 3155 ktons of hydrogen. It also can be noticed that there is no production of hydrogen in Chemelot and Emmen, since it was assumed that there will be no hydrogen electrolysers in both these clusters.

7.2.3 Hydrogen imbalance

The transport of hydrogen and the energy carriers will be based on the imbalance of the supply and demand for hydrogen among the industrial clusters across the Netherlands. Table 13 shows the predicted demand and supply for hydrogen in the Netherlands for the year 2050.

Table 13: Predicted hydrogen supply and demand for the industrial clusters at 2050

Industrial cluster	**Hydrogen supply, ktons per year**	**Hydrogen demand, ktons per year**
Rotterdam	651559 + 1437013	1129556
Amsterdam	601665	802052
Delfzijl	208382	46786
Zeeland	220121	708479
Chemelot	0	434445
Emmen	0	33419
Total	3154737	3154737

It can be noticed from table 13, that an imbalance exists between the supply and demand for hydrogen within the six clusters. Therefore, this would result in excess hydrogen produced in Delfzijl and the imports coming into the port of Rotterdam to be distributed among the other industrial clusters. Table 14 indicates from which clusters the hydrogen shortage in Amsterdam, Zeeland, Chemelot and Emmen can be sourced from, and also the daily demand and supply for each industrial cluster, highlighting the daily imbalance.

Table 14: Allocating hydrogen among the industrial clusters

Industrial cluster	**Hydrogen supply, tons/day**	**Hydrogen demand, tons/day**	**Source**
Rotterdam	5821	3095	Rotterdam
Amsterdam	1648	2197	Rotterdam and Delfzijl
Delfzijl	571	128	Delfzijl
Zeeland	603	1941	Rotterdam
Chemelot	0.0	1190	Rotterdam
Emmen	0.0	92	Delfzijl

The source for each industrial cluster was determined by a simple subtraction of the demand in the particular cluster from the supply available in the same cluster. Positive values indicate that the cluster has an excess while a negative value would indicate that the cluster faces a shortage. In this case, Rotterdam and Delfzjil has an excess while the rest experience shortages. Analysing the location of the clusters, it was logical for Rotterdam to satisfy the shortages in Chemelot and Zeeland since both these clusters were located to the south and closer to Rotterdam. This was the case for Delfzijl in relation to Emmen, as Delfzijl was closer to Emmen compared to Rotterdam. Simple addition of the negative values in Chemelot and Zeeland with the positive value of Rotterdam, resulted in a positive value for Rotterdam and the similar was the result of Delfzijl and Emmen. This positive value indicates that there is still an excess in both Rotterdam and Delfzijl. Since Amsterdam requires large quantities of hydrogen and lays in the north of Rotterdam and south of

Delfzijl, it was assumed that Amsterdam would be supplied by both Rotterdam and Delfzijl. The resulting excess or positive values of both Rotterdam and Delfzijl was able to satisfy the demand of Amsterdam. With this estimation, transport routes and the quantity of hydrogen in each route can be known. This is shown in table 15.

Table 15: Transport of hydrogen across the industrial clusters

Transport route	**Quantity transported, tons/day**
Delfzijl - Emmen	92
Delfzijl - Amsterdam	351
Rotterdam - Amsterdam	198
Rotterdam - Zeeland	1338
Rotterdam - Chemelot	1190

7.2.4 Hydrogen storage

Hydrogen can be stored either in its gaseous form or in its liquid form. The gaseous form of hydrogen has a disadvantage, that it would require a large amount of space as it has a very low density. Liquid storage of hydrogen operates at atmospheric storage but has a higher density and thereby requires less storage space. The disadvantage of this is the fact that hydrogen has to be liquefied before being stored which incurs additional costs and consumes more energy. Therefore, it is assumed that hydrogen is stored as a gas at 30 bar, which is the output pressure from the hydrogen electrolyser. Gaseous storage of hydrogen will be required after the production of hydrogen from the electrolysers before being loaded onto the transport medium. Liquid hydrogen storage would be required at the import terminal at the port of Rotterdam to store the liquid hydrogen coming into the Netherlands from abroad. Storage will also be needed at the destination after unloading. Table 16 and 17 show the storage capacity needed at the source and destination. In the case of liquid hydrogen road transport, storage at the destination will be included with the regasification plant. It is assumed that gaseous hydrogen storage would have negligible energy loss as no loss in pressure is expected during the momentary storage of gaseous hydrogen. Liquid hydrogen is expected to consume energy as to keep it in its liquid state, which is further elaborated in section 7.2.4.

Table 16: Hydrogen storage capacity at the source

Industrial cluster	**Gaseous hydrogen storage capacity at the source, tons/day**	**Liquid hydrogen storage capacity at the port, tons/day**
Rotterdam	1786	10074
Amsterdam	1649	
Delfzijl	571	
Zeeland	604	

Table 17: Hydrogen storage capacity at the destination

Industrial cluster	**Gaseous hydrogen storage capacity at the destination, tons/day**
Emmen	92
Amsterdam	550
Zeeland	1338
Chemelot	1190

7.2.5 Maritime shipping

Maritime shipping will involve the transport of hydrogen from the port of source to the port of Rotterdam in the Netherlands. Currently, there are no ocean-going ships that transport hydrogen in its pure form, but plans have been announced by Kawasaki (http://global.kawasaki.com/en/hydrogen/) to build the world's first liquid hydrogen tanker. This study assumes that hydrogen is to be shipped in its liquid form at cryogenic temperatures similar to LNG ships. Since no ships exist to transport hydrogen, maritime ship transport of hydrogen will be modelled after Liquefied Natural Gas (LNG) tankers. LNG tankers have capacities ranging from 130000m^3 - 170000m^3 with the exception of very large and ultra large tankers, that have capacities of 210000m^3 and 260000m^3 (Raj, Ghandehariun, Kumar, Geng, & Linwei, 2016). The tanks on board the ships are well insulated to hold the liquid in cryogenic temperatures. To help facilitate the cryogenic temperature in the tanks, a small percentage of the transported liquid is held in the tanks and not unloaded at the destination (Raj et al., 2016). This is referred to as the heel which serves to maintain the temperature in the tanks and also an additional fuel source for the ship (Dobrota et al., 2013). Since transport by ship takes days, it is common that some of the liquid escapes as gas and this is known as boil off gases (Dobrota et al., 2013). The boil-off gases are sent to the ship's propulsion system for combustion (Dobrota et al., 2013). Re-liquefaction plants are not installed on the ship, as the ships are designed to hold maximum capacity (Dobrota et al., 2013).

At the port of Rotterdam, regasification plants would be required to be able to regasify the unloaded liquid hydrogen from the ships. Assuming that regasification of liquid hydrogen is similar to liquid natural gas, the liquid hydrogen is unloaded from the ship and stored as a liquid in storage tanks (Dobrota et al., 2013). Depending on the demand for hydrogen, the gas is regasified accordingly. Liquid hydrogen can also be loaded directly onto the trucks for liquid road transport (Dobrota et al., 2013). Therefore, the system boundaries for hydrogen maritime shipping starts from the purchase of liquid hydrogen from the port of source, shipping liquid hydrogen and either regasification or storage at the port of Rotterdam. This is depicted in figure 9.

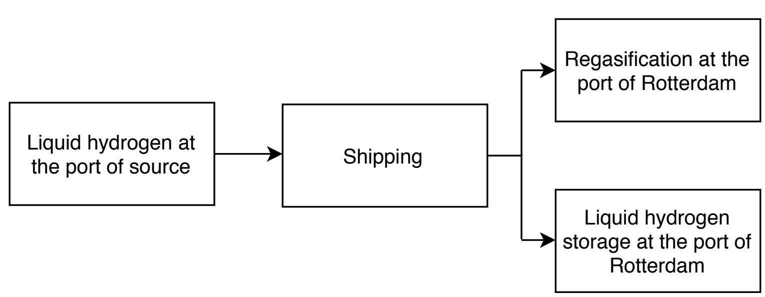

Figure 9: System boundaries for hydrogen shipping

Now the transport of hydrogen by ships can be modelled. The parameters used for transporting hydrogen by ship is detailed in table 18.

Table 18: Parameters used for modelling hydrogen shipping (Dobrota et al., 2013)(Polemis, 2013)(Rodrigue et al., 2017)(Rogers, 2018)

Parameter	**Value**	**Unit**
Capacity of ship	150000	m^3
Speed	19 (35)	knots (km/h)
Distance	8000	km
Boil-off losses	0.12	% per day
Heel	4	% of total capacity
Fuel consumption	48	tons/day
Time at port (source and destination)	3	days

For this thesis, a ship of 150000 m^3 is assumed to transport the liquid hydrogen. A distance of 8000 km is assumed, as it is expected that liquid hydrogen will be shipped from the middle east. For a capacity of 150000 m^3, using a density of 70.8 kg/m^3 for liquid hydrogen, 10620 tons of hydrogen can transported in a single trip. To be able to travel 8000 km at 35 km/h, a total of 9.5 days is required which results in boil-off losses of 121 tons of liquid hydrogen. Since a heel of 4% has to be maintained in the tanks, the net capacity that can be unloaded from the ship will be 10074 tons of hydrogen. Further on, depending on the mode of transport on land, the liquid hydrogen has to either be regasified or transported as a liquid. The daily demand for hydrogen imports is 4212 tons, thereby one trip can satisfy two days worth of demand. Therefore, only one ship has to be deliver liquid hydrogen every two days.

The energy consumption for maritime shipping takes into account the energy used for hydrogen production and liquefaction at the port of source, fuel consumption of the ship and regasification with liquid storage or only liquid storage at the port of Rotterdam, depending on further transport on land. The regasification process for hydrogen is expected to be similar to Liquefied Natural Gas (LNG), except that more energy would be required since liquid hydrogen is at a cryogenic temperature of -253°C while LNG is at -163°C. The regasification process takes place by compressing the liquid and then heating it to atmospheric temperature (Bruno, Bevilacqua, & Arcuri, 2017). For LNG regasification, the energy required is estimated to be 1.5% of the energy content of LNG (Bruno et al., 2017). For this thesis, the energy required for the regasification of liquid hydrogen is assumed to be 1.5% of the liquid hydrogen energy content similar to LNG. Regasification plants usually encompass liquid storage and the regasification plant. The energy consumption estimated by Bruno et.al for regasification, does not account for the energy consumption for liquid storage, which has to be estimated. Bartel et,al. estimates liquid hydrogen storage to have an energy consumption of 1.82 kWh/kg of liquid hydrogen (Bartels, 2008). This is associated to the energy consumed by the pumps to re-liquefy the hydrogen gases that boil-off, as a result of liquid hydrogen absorbing heat (Bartels, 2008). The parameters used to estimate the energy consumed for hydrogen maritime shipping is shown in table 19. Table 20 shows the energy consumed for two scenarios; 1) Regasification is needed, since further transport on land will be through compressed hydrogen road transport or pipeline transport and 2) Only liquid storage would be needed, as hydrogen will be transported further by liquid hydrogen road tankers.

Table 19: Parameters used to estimate the energy consumed for hydrogen shipping (E4techSarl & ElementEnergy, 2014)(Stolzenburg & Mubbala, 2013)(Engineering Toolbox, 2003)

Parameter	**Value**	**Unit**
Energy required for hydrogen production	53	kWh/kgH_2
Energy required for hydrogen liquefaction	6.76	MWh/kgH_2
Energy content of liquid hydrogen	2.78	MWh/m^3H_2
Energy density of HFO	39000	MJ/tons

Table 20: Estimated energy consumption of hydrogen shipping

Sceanrio	**Production and liquefaction, MWh/day**	**Fuel consumption, MWh/day**	**Regasification, MWh/day**	**Liquid storage, MWh/day**	**Total, MWh/day**
Compressed hydrogen transport	354496	3252	5934	9193	372874
Liquid hydrogen transport	354496	3252	-	9193	366940

The energy consumption is dominated by the production and liquefaction of hydrogen, making all the other components almost negligible in comparison. As expected, the energy consumption is higher for compressed road transport as regasification is also required.

7.2.6 Pipeline transport

Globally, around 4500 km of hydrogen pipelines exist with the longest pipeline between Belgium and Germany (Hydrogen Europe, n.d.). The transport of hydrogen by pipeline involves multiple components other than the pipeline itself. Figure 10 shows in detail the system components involved in the transport of hydrogen through pipeline. As seen in figure 10, the system boundaries for transporting hydrogen by pipelines includes: hydrogen production from electrolysers with gaseous hydrogen storage, hydrogen import with regasification at the port of Rotterdam, compression and decompression, and the transport medium - pipeline.

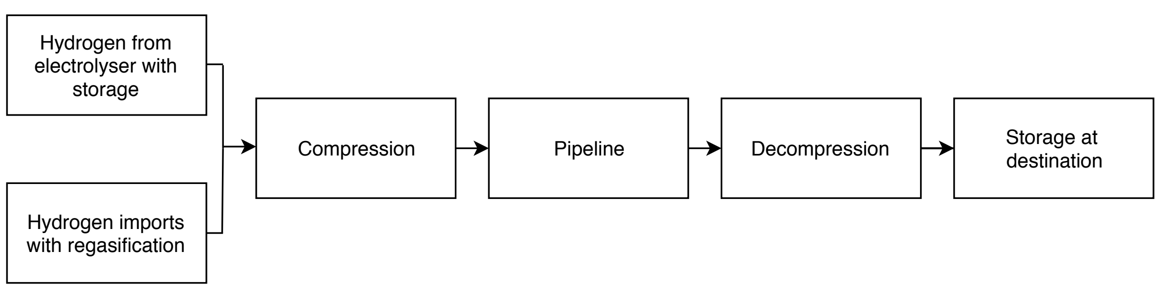

Figure 10: System boundaries for hydrogen pipelines

The design for pipelines remain the same for all the energy carriers including hydrogen. Since hydrogen is a gas that has a very low density, construction of the pipeline and the materials is more complex when compared to other petroleum products that are transported through pipelines. Hydrogen pipelines would require special seals to prevent leakage from the pipelines due to its low density, also pipelines would require coatings like Galvalume to prevent hydrogen embrittlement in the steel pipes (Parker, 2004) (Weber et al., 2013). Table 21 shows the parameters used to design the hydrogen pipeline.

Table 21: Hydrogen pipeline design parameters (Weber et al., 2013)(Sashi Menon, 2005)(Knoppe, 2015)(Engineering Toolbox, n.d.)

Parameter	**Value**	**Unit**
Average pressure in the pipeline	3.5	MPa
Design factor	0.5	
Roughness factor	0.00002	m
Base pressure of the pipeline	0.101	MPa
Base temperature of the pipeline	288	K
Density of steel	7900	kg/m3
Corrosion allowance	0.001	m
Average compressibility factor	0.9	
Molecular mass	0.00202	kg/mol
Gas gravity	0.069	
Average temperature	288	K
Density of hydrogen	2.397	kg/m3
Specific heat	1.41	
Viscosity	0.000088	P

Hydrogen pipelines for all the routes will be designed using the design procedure mentioned in figure 5 taking into account the data in table 21. Table 22 lists the results of the pipeline designs including the dimensions and costs for utilizing different steel grades. Also noticeable in table 22, for different steel grades, the thickness needed for the pipeline changes due to the varying yield stress. The thickness plays a major role in determining the costs of the pipeline and thereby in all cases, the steel grade x65 was the most economical except for the Delfzijl - Emmen route in which steel grade x52 is cheaper. This could be attributed to the fact that the quantity of hydrogen transported is very less compared to the other routes. NPS (nominal pipe size) is the commercial term referring to the outer diameter of the pipeline, measured in inches. The Rotterdam - Chemelot pipeline route has been assessed as two separate pipelines, as in the proposed network, the pipeline has two segments with a junction in between. It is also assumed that a compressor station will be present in the junction connecting both the segments.

The low density and low viscosity of hydrogen has an effect on the velocity of hydrogen flowing through the pipeline. To make sure, the velocity was within the NORSOK standards of 60 m/s, either the pressure had to be reduced or the pipeline diameter had to increase. The average pressure used in the pipeline was chosen to be 3.5 MPa, as high pressures proposed in literature of 6 - 7 MPa for transmission lines would increase the velocities of hydrogen to very high speeds (Yang & Ogden, 2007)(Weber et al., 2013). This could be due to the fact that the amount of hydrogen transported in this thesis is lower when compared to other literature, who have modelled pipelines for higher quantities (Yang & Ogden, 2007)(Weber et al., 2013). The average pressure chosen is higher than currently operating hydrogen pipelines of 2 - 2.5 MPa but similar to the distribution pipeline pressure proposed by Weber et.al (Weber et al., 2013). Therefore, it was decided not to reduce the pressure lower than 3.5 MPa and rather increase the diameter of the pipeline to reduce the velocity of hydrogen further, if needed.

Table 22: Hydrogen pipeline design

Route	**Amount, tons/day**	**Distance, km**	**Steel grade**	**Thickness, m**	**Outer diameter, m**	**NPS, inch**	**Cost of pipeline, M€**
Delfzijl - Emmen	92	60.7	x42	0.0022	0.1016	3.5	0.37
			x52	0.0019	0.1016	3.5	0.33
			x65	0.0017	0.1016	3.5	0.34
			x70	0.0017	0.1016	3.5	0.35
Delfzijl - Amsterdam	351	176	x42	0.0033	0.1937	7	3.039
			x52	0.0028	0.1937	7	2.62
			x65	0.0024	0.1937	7	2.56
			x70	0.0023	0.1937	7	2.67
Rotterdam - Amsterdam	198	59.6	x42	0.0027	0.1414	5	0.608
			x52	0.0023	0.1414	5	0.53
			x65	0.002	0.1414	5	0.53
			x70	0.0019	0.1414	5	0.56
Rotterdam - Zeeland	1338	63.3	x42	0.0058	0.4064	16	4.058
			x52	0.0047	0.4064	16	3.37
			x65	0.0039	0.4064	16	2.72
			x70	0.0036	0.4064	16	3.25
Rotterdam - Chemelot							
Rotterdam - Nijmegen	1190	81.1	x42	0.0052	0.3556	14	4.08
			x52	0.0043	0.3556	14	3.40
			x65	0.0035	0.3556	14	3.21
			x70	0.0033	0.3556	14	3.31
Nijmegen - Chemelot	1190	81.1	x42	0.0052	0.3556	14	4.55
			x52	0.0043	0.3556	14	3.80
			x65	0.0035	0.3556	14	3.56
			x70	0.0033	0.3556	14	3.70

To be able to compress hydrogen to the respective transport pressure, compressors will be required. Table 23 shows the compressor capacities required for pipelines, which was designed using equation 14. The suction pressure for the compressor is 3 MPa, which is the storage pressure of hydrogen storage. The parameters used for modelling the compressors have been listed in the bottom half of table 21, as similar parameters are used. Another assumption that is made in this thesis, is that the decompressor at the end of the pipeline is assumed to be similar to the compressor at the beginning of the pipeline, and thereby the compressor capacities are the same. A decompressor is used at the receiving end of the pipeline to reduce the pressure of hydrogen from transport pressure to distribution pressure.

Table 23: Hydrogen pipeline compressor sizes

Transport route	Compressor size, kW	Discharge pressure, MPa
Delfzijl - Emmen	263	3.5
Delfzijl - Amsterdam	1011	3.5
Rotterdam - Amsterdam	569	3.5
Rotterdam - Zeeland	3851	3.5
Rotterdam - Nijmegen	3426	3.5
Nijmegen - Chemelot	1937	3.5

In the case of hydrogen pipeline transport, energy is only consumed by the compressors during loading and unloading, which is estimated to be 531 MWh/day.

7.2.7 Compressed road transport

Hydrogen can be transported by road in its compressed form or liquefied form. The compressed form of hydrogen is usually transported in steel tube trailers similar to that of natural gas, at 250bar pressure (Yang & Ogden, 2007). In recent years, composite tube trailers have been developed to transport hydrogen at higher pressures to accommodate a higher volume of hydrogen that can be transported. Companies like Hexagon Lincoln (https://www.hexagonlincoln.com/) have commercialized composite tube trailers that transport hydrogen at 250, 350 and 500 bar. As a consequence of the high pressures required in the tube trailers, the loading and unloading time of the tube trailers have increased, which adds to the delivery time of hydrogen. Although in the past, loading and unloading times have taken a few hours, technical advances have made it possible to either load or unload tube trailers under one hour nowadays (Linde, n.d.).

The system components involved in the transport of compressed hydrogen by road can be seen in figure 11. The system components are similar to that of hydrogen pipeline transport except for the transport medium - tube trailers.

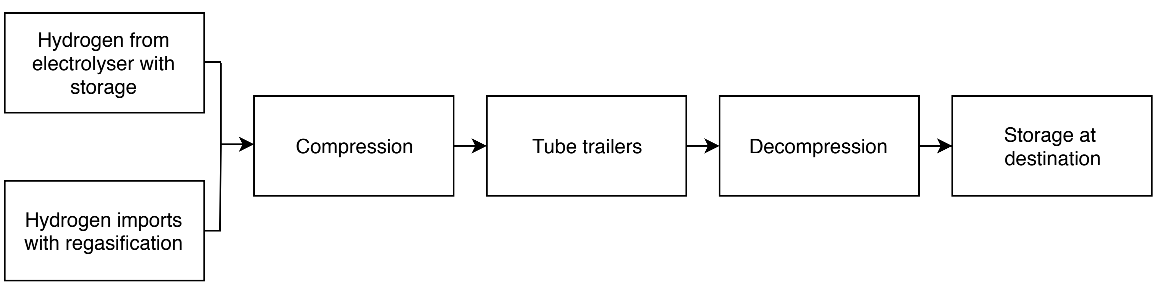

Figure 11: System boundaries for compressed hydrogen road transport

The first step for modelling compressed hydrogen road transport, is to determine the type of transport vehicle used and how many of it would be required in each route. In this study, composite tube trailers are used to transport compressed hydrogen by road, as it is likely that composite tube trailers will be developed further and used in the future. The 250 bar, 350 bar and 500 bar composite tube trailers by Hexagon Lincoln are used in this study. Eventhough, the 500 bar tube trailer has a total weight (including payload) of 46 tons which surpasses the EU regulations, it is assumed that in the future the regulations will evolve to accommodate heavier vehicles. It is also assumed that the loading and unloading times for the composite trailers, to be one hour each at the source and destination. Table 24 shows the types of tube trailers that will be used in this study.

Table 24: Compressed hydrogen tube trailers (Baldwin, n.d.)(Hexagon lincoln, 2017)

Type	**Total weight, ton**	**Operating pressure, MPa**	**Capacity, kg**
Hexagon Lincoln Titan Magnum Type 4 All-Carbon Hydrogen 250 bar	26.9	25	900
Hexagon Lincoln Titan V Magnum Trailer - 350 bar	34.2	35	1050
Hexagon Lincoln Titan V Magnum Trailer - 500 bar	45.7	50	1500

To be able to find out how many tube trailers would be required in each transport route, a few parameters have to be decided. The distance for each route is estimated using google maps and the rest of the parameters have been listed in table 25.

Table 25: Compressed hydrogen road transport technical parameters (Yang & Ogden, 2007)(Wulf & Zapp, 2018)

Parameter	**Value**	**Unit**
Truck speed (average)	50	km/h
Fuel consumption	32	l/100km
Unloading and loading time	2	hrs

In most cases of road transport of chemicals, either the tube trailers unload at the destination and are filled up with other chemicals and transported back, or the tube trailers are stored at the destination. For the sake of simplicity, it is assumed that the tube trailers unload at the destination and return empty. In this case, the return trip has no economic benefit rather a loss, as the drivers still have to be paid and fuel is consumed. Using the parameters in table 25, the time taken for the tube trailers to travel each route including the loading and unloading times can be estimated. This will in turn be able to give an estimate of the number of tube trailers required for each transport route. Table 26 shows the number of tube trailers required at the different pressures.

Table 26: Number of tube trailers and trips needed for compressed hydrogen road transport

Road routes	**Amount of hydrogen, tons/day**	**Distance, km**	**Time taken per trip, hrs**	**No. of trips required**	**Tube trailers needed (250 bar)**	**Tube trailers needed (350 bar)**	**Tube trailers needed (500 bar)**
Delfzijl - Emmen	92	76	3.52	3	35	30	21
Delfzijl - Amsterdam	351	222	6.44	1	397	335	235
Rotterdam - Amsterdam	198	75	3.5	3	75	63	44
Rotterdam - Zeeland	1338	83	3.66	3	505	425	298
Rotterdam - Chemelot	1190	179	5.58	2	673	567	397

To load hydrogen onto the tube trailers at the respective transport pressure at the source, and unload the hydrogen at the destination, compressors will be required. Table 28 shows the compressor capacities required for compressed road transport, which was designed using equation 14. The suction pressure for the compressor is 3 MPa, which is the storage pressure of hydrogen storage. The parameters used for modelling the compressors have been listed in table 27. It is also assumed that the decompressors at the destination to unload the hydrogen, is similar to the compressors at the source and thereby the compressor capacities are similar. The number of compressors required for each route is assumed to be equal to the number of tube trailers required for each route. This assumption is based on the fact that all the tube trailers are expected to be loaded at the same time and thereby the compressors cannot be shared.

Table 27: Hydrogen compressor design parameters for road transport (Weber et al., 2013)(Sashi Menon, 2005)(Engineering Toolbox, n.d.)

Parameter	**Value**	**Unit**
Average compressibility factor	0.9	
Molecular mass	0.00202	kg/mol
Gas gravity	0.069	
Average temperature	288	K
Density of hydrogen - 250 bar	18.15	kg/m3
Density of hydrogen - 350 bar	22.76	kg/m3
Density of hydrogen - 500 bar	30.811	kg/m3
Specific heat	1.41	
Viscosity	0.000088	P

Table 28: Compressor capacities for compressed hydrogen road transport

Vehicle type	**Compressor size, kW**	**Discharge pressure, MPa**
Hexagon Lincoln Titan Magnum Type 4 All-Carbon Hydrogen 250 BAR	1253	25
Hexagon Lincoln Titan V Magnum 350 BAR	1819	35
Hexagon Lincoln Titan V Magnum 500 BAR	3363	50

The energy efficiency of compressed hydrogen road transport can be estimated, since all the equipments required for compressed hydrogen road transport has been discussed. With the number of tube trailers needed for each route and the time taken per trip, it is possible to calculate the fuel consumption for transporting the compressed hydrogen. This is shown in table 29

Table 29: Fuel consumption of the tube trailers used for compressed hydrogen road transport

Route	**Fuel consumption (250 bar tube trailer), litres/day**	**Fuel consumption (350 bar tube trailer), litres/day**	**Fuel consumption (500 bar tube trailer), litres/day**
Delfzijl - Emmen	5107	4378	3064
Delfzijl - Amsterdam	56406	47597	33389
Rotterdam - Amsterdam	10800	9072	6336
Rotterdam - Zeeland	80477	67728	47489
Rotterdam - Chemelot	154198	129911	90961
Total	306988	258685	181239

It is assumed that diesel will be used as the fuel for road transport vehicles in this thesis. Diesel has an energy density of 9.7 kWh/litre (Wurster & Zittel, 1994). Using this value, the energy consumption for 250 bar, 350 bar and 500 bar tube trailers can be calculated. This is shown in table 30 alongside the energy required for the compressors for loading and unloading, the compressed hydrogen.

Table 30: Energy consumption of compressed hydrogen road transport

Transport vehicle	**Loading and unloading, MWh/day**	**Tube trailer, MWh/day**	**Total, MWh/day**
250 bar	101278	2978	104256
350 bar	123976	2509	126485
500 bar	160612	1758	162370

Loading and unloading consumes more energy than the tube trailer itself. As the transport pressure increases, the energy consumption for loading and unloading increases while the energy consumption for the tube trailers decrease. This results in the net increase of energy consumption as the transport pressure increases. The energy saved by the tube trailer does not compensate for the increase in the energy consumption for loading and unloading.

7.2.8 Liquid road transport

Liquid hydrogen is transported by insulated steel tankers at a cryogenic temperature of -253°C (Wulf & Zapp, 2018). This form of transporting hydrogen has been the most preferred form of transportation by road, as it is considered more economical compared to compressed hydrogen road transport (Wulf & Zapp, 2018)(Yang & Ogden, 2007). It has to be noted that the comparisons were made to compressed hydrogen transport by steel tube trailers, which was limited by the operating pressures, and thereby the volumes that could be transported. Liquid hydrogen road tankers have a maximum capacity of 4300 kg of hydrogen and the time taken to either load or unload liquid hydrogen tankers is approximately three hours (Wulf & Zapp, 2018), which is relatively long compared to compressed hydrogen tube trailers. The system components involved in the transport of liquid hydrogen by road can be seen in figure 12. The system components vary with respect to compressed hydrogen road transport, as liquefaction and regasification of hydrogen is required at the source and destination, respectively. Another difference, is that hydrogen imports do not have to be regasified, instead only liquid hydrogen storage will be required at the port of Rotterdam. Regasification of liquid hydrogen also includes storage for liquid hydrogen.

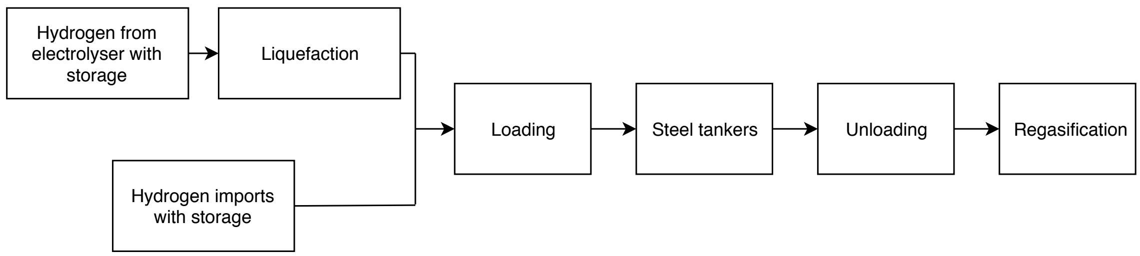

Figure 12: System boundaries for compressed hydrogen road transport

Following the similar trend in literature, steel road tankers are used for transporting liquid hydrogen in this thesis. The technical parameters for modelling liquid hydrogen road transport remains the same as compressed hydrogen road transport, except for the loading and unloading time for liquid hydrogen road transport is three hours each, at the source and destination (Wulf & Zapp, 2018). The road tanker is expected to have a maximum capacity of 4300 kg of hydrogen with a total weight of 31 tons on the road at an operating pressure of 1 atm (Wulf & Zapp, 2018). Table 31 shows the number of tankers and trips needed for each route on a daily basis, to satisfy the hydrogen demand.

Table 31: Number of trips and tankers needed for each route

Road routes	**Amount of hydrogen, tons/day**	**Distance, km**	**Time taken per trip, hrs**	**No. of trips required**	**Tankers needed**
Delfzijl - Emmen	92	76	7.52	1	22
Delfzijl - Amsterdam	351	222	10.44	1	82
Rotterdam - Amsterdam	198	75	7.5	1	47
Rotterdam - Zeeland	1338	83	7.66	1	312
Rotterdam - Chemelot	1190	179	9.58	1	277

To be able to load liquid hydrogen onto the steel road tankers, pumps will be required. Table 33 shows the pump capacities required for liquid hydrogen road transport which was modelled using equation 15. The parameters used to model the pumps are listed in table 32. Similar to compressed hydrogen road transport, the pump capacities for loading is assumed to be similar to unloading for liquid hydrogen road transport, and the number of pumps used is equal to the number of road tankers required for each route.

Table 32: Liquid hydrogen pump design data (Weber et al., 2013)(Sashi Menon, 2005)

Parameter	**Value**	**Unit**
Molecular mass	0.00202	kg/mol
Gas gravity	0.069	
Density of liquid hydrogen	70.8	kg/m3

Table 33: Pump capacity for liquid hydrogen transport

Vehicle type	**Pump capacity, kW**	**Discharge pressure, MPa**
Steel tankers	176	0.1

Liquefaction plants are required at the source to liquefy hydrogen. The liquefaction process is a complex process, employing compressors and heat exchangers at various stages of the process to produce liquid hydrogen from gaseous hydrogen (Stolzenburg & Mubbala, 2013). The gaseous hydrogen is first pressurised to 82 bar, which is then pre-cooled through heat exchangers using a mixed refrigerant (Stolzenburg & Mubbala, 2013). The cryogenic cooling process further reduces the temperature of the pre-cooled hydrogen to about -253°C by employing two Brayton cycles (Stolzenburg & Mubbala, 2013). Liquid hydrogen is still at a very high pressure and thereby the final step reduces the pressure of the liquid hydrogen through an expansion stage (Stolzenburg & Mubbala, 2013). The liquefaction process is an energy intensive process, when compared to compression, liquefaction requires approximately three times more electricity (Yang & Ogden, 2007). The energy required for hydrogen liquefaction has been estimated to be 6.76 MWh/ton of liquid hydrogen (Stolzenburg & Mubbala, 2013). Table 34 shows the liquefaction plant capacities needed at Delfzijl and Rotterdam and the energy required for each plant.

Table 34: Hydrogen liquefaction plant capacities

Industrial cluster	**Liquefaction plant size, ton/day**	**Liquid hydrogen output, ton/day**	**Energy consumption, MWh/day**
Delfzijl	554	443	2997
Rotterdam	2232	1786	12072

The liquefaction plant is expected to operate at 80% of its total capacity as to mimic a practical scenario where operational capacity is not at 100%, and necessary maintenance stops reduce total output. The capacity at Rotterdam is lower than what would have been needed, due to hydrogen being transport via ship as a liquid to the port of Rotterdam, which can be loaded directly onto the road tankers after being stored at the port. This eliminates the need for a higher liquefaction capacity at Rotterdam. At the destination, liquid hydrogen will be unloaded from the road tankers into a liquid storage. For liquid hydrogen to be used further, the hydrogen has to be regasified. Table 35 shows the regasification capacities required at each destination and the energy consumption for each.

Table 35: Regasification plant capacity and energy requirements at the destination

Industrial cluster	**Regasification plant capacity, tons/day**	**Energy consumption, (regasification) MWh/day**	**Energy consumption, (storage) MWh/day**
Emmen	92	54	167
Amsterdam	549	323	999
Zeeland	1338	788	2435
Chemelot	1190	701	2166

The energy used for liquid hydrogen road transport would include energy consumed for liquefaction, loading, transport, unloading and regasification. First the fuel consumption for transporting liquid hydrogen has to be estimated, which is shown in table 36.

Table 36: Fuel consumption of the road tankers used for liquid hydrogen road transport

Route	**Fuel consumption litres**	**Energy consumption, MWh/day**
Delfzijl - Emmen	1070	10
Delfzijl - Amsterdam	11651	113
Rotterdam - Amsterdam	2256	22
Rotterdam - Zeeland	16573	161
Rotterdam - Chemelot	31733	308
Total	63283	614

The final energy consumption for liquid hydrogen road transport can now be estimated. This is shown in table 37 alongside the energy required for the pumps for loading and unloading, liquefaction plants and regasification plants.

Table 37: Energy consumption of liquid hydrogen road transport

Road tanker MWh/day	**Loading and unloading, MWh/day**	**Liquefaction, MWh/day**	**Regasfication, MWh/day**	**Storage, MWh/day**	**Total, MWh/day**
614	6265	15068	1866	5767	29581

As seen in the table, liquefaction of hydrogen consumes more than half the energy while the energy consumed by the road tanker is almost negligible. This indicates that the transport mode itself does not consume much energy but the preparation of hydrogen for transport consumes much more energy.

7.2.9 Energy efficiency of hydrogen transport

The energy consumed by the different transport modes have been estimated but as a whole system, the energy efficiency matters. Systems with low energy efficiencies, would reflect that more energy is lost in the process of production and transportation the energy carrier from source to destination. Energy efficiency of a system in this thesis is defined as the energy available divided by the energy spent by the system, which extends from production at the source to delivery and storage at the destination. This is shown in the equation below.

$$Energy_{eff} = \frac{Energy_{useful}}{Energy_{spent}} \tag{16}$$

$\text{Energy}_{\text{useful}}$ is the energy available for consumption at the destination and E_{spent} is the energy consumed by the system. Table 38 shows the energy efficiency of the hydrogen transport systems.

Table 38: Energy efficiency of hydrogen transport systems

Transport medium	**Production, MWh/day**	**Storage, MWh/day**	**Transport medium, MWh/day**	**Import, MWh/day**	**Total, MWh/day**	**Efficiency**
Pipeline	275040	-	530.68	372874	648445	52%
Compressed road - 250 bar	275040	-	104256	372874	752170	45%
Compressed road - 350 bar	275040	-	126486	372874	774400	44%
Compressed road - 500 bar	275040	-	162370	372874	810284	42%
Liquid road	275040	-	29580	366940	671560	51%

Hydrogen pipeline transport has the highest energy efficiency of 52% followed closely by liquid hydrogen road transport at 50%. Compressed hydrogen road transport has a relatively lower efficiency as the transport modes consume much more energy. The efficiency reduces further as higher pressure tube trailers are used, which can be attributed to the fact that compressor capacities increase as the transport pressure increases. This clearly indicates that compressed road transport is far less energy efficient compared to pipeline and liquid road transport.

7.3 Ammonia transport

Ammonia is one of the energy carriers that was shortlisted in chapter 3. As previously discussed, ammonia is produced using the Haber-Bosch process, which requires hydrogen and nitrogen as process inputs. Hydrogen and nitrogen are produced either through steam reforming of methane or gasification of coal (Bartels, 2008). Hydrogen and nitrogen is further compressed to 120 - 220 bar before entering the ammonia synthesis loop (synloop), wherein the inputs pass over a ruthenium based-catalyst in a series of loops to make sure all the inputs participate in the reaction, to produce the maximum amount of ammonia (Bartels, 2008). For this thesis, it is expected that all the energy carriers are produced using renewable energy. Thereby, the process is slightly modified in which hydrogen is produced using electrolysis and nitrogen is captured using an air-separation unit before entering the synloop which remains the same (Bartels, 2008). Hydrogen production has already been discussed in section 7.2.1, therefore only nitrogen capture and the synloop process has to be discussed. The air-separation unit first filters the air to remove unwanted particles, then through a series of compression, cooling and evaporation, the nitrogen is separated from the oxygen and other compounds/elements present in the air (Bartels, 2008). The ammonia synthesis reaction is shown in the equation below.

$$3H_2 + N_2 \rightleftharpoons 2NH_3 \tag{17}$$

Since the production of hydrogen has been modelled in section 7.2.1, the amount of ammonia that can be produced in the Netherlands will depend on it. The rest of the demand will have to be satisfied by ammonia imports through the port of Rotterdam, similar to that of hydrogen transport. From the equation above, 1 kg of H_2 can produce 5.6 kg of ammonia and with a process efficiency of 80%, 4.5 kg of ammonia can be produced from 1 kg of hydrogen (Frattini et al., 2016)(ARPA-E, 2016). To account for maintenance stops and repairs needed, it is assumed that the operating capacities of the ammonia plants are at 80%.

D. Frattini et.al, reports an estimated energy use of 14.3 kW/kgNH_3 of which 95% of the energy is used for the hydrogen electrolyser which amounts to 13.6 kW/kgNH_3, while the rest 5% is used for the air separation unit (ASU) for nitrogen capture and the synloop process (Frattini et al., 2016). The estimated energy use is higher than the US Department of Energy, which has made an estimate of 9.5 kW/kgNH_3 (ARPA-E, 2016). For this thesis, the estimated energy use of 14.3 kW/kgNH_3 is used as to take a conservative approach in modelling the ammonia production process. Table 40 shows the capacity of the ammonia plants, alongside the energy consumed by the plants. The parameters used to model the ammonia production plants are listed in table 39.

Table 39: Parameters used for modelling ammonia production plants (Bartels, 2008)(Frattini et al., 2016)

Parameter	**Value**	**Unit**
Density	682	kg/m^3
Process efficiency	80	%
ASU electricity usage	0.22	kW/kgNH_3
Synloop electricity usage	0.44	kW/kgNH_3
Scaling factor	0.65	
Operating capacity	80	%

Table 40: Ammonia production in the Netherlands

Industrial cluster	**Hydrogen production, tons/day**	**Ammonia production, tons/day**	**Electricity usage, MWh/day**
Rotterdam	1785	6421	4282
Amsterdam	1648	5929	3954
Delfzijl	571	2054	1369
Zeeland	603	2169	1447

7.3.1 Ammonia reforming

To determine the quantity of ammonia that needs to be transported, the demand for ammonia should also be known. The demand for ammonia will be based on the hydrogen demand at each industrial cluster and the ability to reform ammonia back to hydrogen. To be able to get hydrogen from ammonia, ammonia has to be reformed either by autothermal reforming or ammonia electrolysis (T. Lipman & Shah, 2007). Autothermal reforming of ammonia is an endothermic decomposition reaction which requires a wide range of temperatures between 300°C - 2000°C depending on the plant conditions (T. Lipman & Shah, 2007). A wide range of efficiencies from 63 - 99% have been reported for the reforming process by research institutes and manufacturers (T. Lipman & Shah, 2007)(Bartels, 2008). Ammonia electrolysis produces hydrogen by using an alkaline electrolytic cell. The advantage of using ammonia electrolysis is the amount of energy/electricity used is very low. Despite this, the ammonia electrolysis process is very slow, which makes the process not feasible when scaling up (T. Lipman & Shah, 2007). Therefore, most industries produce hydrogen from ammonia using autothermal reforming of ammonia (T. Lipman & Shah, 2007). Therefore in this thesis, autothermal reforming of ammonia is modelled. Using a process efficiency of 80% and the simple mass balance as seen in equation 17, table 41 shows the demand for ammonia at each industrial cluster.

Table 41: Ammonia demand in the Netherlands

Industrial cluster	**Hydrogen demand, tons/day**	**Ammonia demand, tons/day**
Rotterdam	3095	21742
Amsterdam	2197	15438
Delfzijl	128	901
Zeeland	1941	13637
Chemelot	1190	8362
Emmen	92	643
Total		60723

With the supply and demand for ammonia known, the quantity of ammonia that will have to imported to satisfy the demand is estimated to be 44149 tons of ammonia per day. Now, the quantity of ammonia that will have to be transported across the Netherlands can be estimated, which is shown in table 42

Table 42: Ammonia transported along each route in the Netherlands

Transport routes	**Quantity of ammonia, tons/day**
Delfzijl - Emmen	643
Delfzijl - Amsterdam	510
Rotterdam - Amsterdam	8999
Rotterdam - Zeeland	11468
Rotterdam - Chemelot	8362

Since it is possible to combust ammonia to produce energy, it is not necessary to reform all of the ammonia back to hydrogen (Bartels, 2008). In this thesis, it is assumed that only hydrogen required for non-energy applications, will be reformed back. The Gasunie 2050 survey reports, that 96 PJ of the 444 PJ is utilized for non-energy applications (Gasunie, 2018). Thereby, 96 PJ of hydrogen will be required to be reformed back from ammonia. Since no specific distribution of this 96 PJ of hydrogen has been specified, it is assumed to be distributed in the similar manner as to how the demand of 444 PJ of hydrogen was divided among the six industrial clusters. This would be the same case for all the other energy carriers, as all of them can be combusted to generate energy.

The parameters used to model autothermal reforming of ammonia is listed in table 43. As seen in the table, heat is required for the process to take place. This thesis takes a renewable approach, and therefore fossil fuels like natural gas or coal will not be used to provide heat as is currently done in the Netherlands. Since hydrogen itself can be combusted like natural gas, it is assumed that some of the hydrogen transported is combusted to provide the heat required for ammonia reforming. Since hydrogen turbines are yet to become commercial and in many cases, companies have successfully either combusted hydrogen blended with natural gas or adapted natural gas turbines to combust hydrogen, hydrogen combustion is modelled after natural gas combustion (Noon, 2019). Natural gas turbines have an efficiency of 55 - 65%, thereby it is assumed that hydrogen combustion will have an efficiency of 60% (Jansohn, 2013).

Table 43: Parameters used for modelling ammonia reforming plants (Bartels, 2008)(T. Lipman & Shah, 2007)(IEA, 2019)(van Wijk, 2018)

Parameter	Value	Unit
Density	682	kg/m^3
Process efficiency	80	%
Heat required	11.2	kWh/kgH_2
Hydrogen combustion efficiency	60	%
Hydrogen energy density	141	MJ/kg

Using the parameters listed, table 44 shows the ammonia reformer plant capacities at each industrial cluster, as well as the respective energy demands.

Table 44: Ammonia reformers at the six industrial clusters

Industrial cluster	Hydrogen demand, tons/day	Ammonia reformer capacity, tons/day	Heat demand, MWh/day	Hydrogen combusted, tons/day
Rotterdam	669	4701	7494	319
Amsterdam	475	3338	5321	226
Delfzijl	28	195	310	13
Zeeland	420	2949	4700	200
Chemelot	257	1808	2882	123
Emmen	20	139	222	9

7.3.2 Ammonia storage

Ammonia can be stored in either pressurized storage tanks or low temperature storage tanks. In pressurised storage vessels, ammonia can be stored as a liquid as long as the pressure is higher than 862 kPa at ambient conditions (Papavinasam, 2014). Therefore, ammonia is stored in pressure storage tanks at 17 bar (1700 kPa) also to account for increasing temperature of the tanks during hot periods, which may cause the ammonia to become gaseous (Bartels, 2008). Low-temperature vessels on the other hand, are maintained at -34°C to make sure that ammonia is in its liquid form at all times (Bartels, 2008). Low-temperature storage vessels are used for large-scale ammonia storage and pressurised storage tanks are used for small scale storage (Bartels, 2008). Thereby in this thesis, low-temperature ammonia storage is used, after the ammonia production plant, at the port of Rotterdam for the ship to unload and at the destination before ammonia is reformed back to hydrogen. In the case of low-temperature storage of ammonia, energy is used by pumps within the storage tanks to: 1) Re-liquefy the ammonia that has turned to gas as a result of heat absorption from the outside and 2) To lower the temperature of ammonia coming into the storage tanks from the production plant (Bartels, 2008). Bartel et.al, has estimated the energy used for this to be 0.038 $kWh/kgNH_3$ (Bartels, 2008). For shipping, storage tanks would only require energy used for the pumps and this is estimated to be 0.032 $kWh/kgNH_3$ by Bartel et.al, (Bartels, 2008). Table 45 and 46 shows the storage tank capacities needed at the source and destination with the energy required for each.

Table 45: Ammonia storage capacity at the source

Industrial cluster	**Storage capacity at the source, tons/day**	**Energy use, MWh/day**	**Storage capacity at the port, tons/day**	**Energy use, MWh/day**
Rotterdam	6421	244	51757	1663
Amsterdam	5929	225	-	-
Delfzijl	2054	78	-	-
Zeeland	2169	82	-	-

Table 46: Ammonia storage capacity at the destination

Industrial cluster	**Storage capacity at destination, tons/day**	**Energy use, MWh/day**
Emmen	643	24
Amsterdam	9509	361
Zeeland	11468	435
Chemelot	8363	317

7.3.3 Maritime shipping

As mentioned earlier, the similarity between ammonia and LPG allows ammonia to be transported using LPG infrastructure. LPG ships are of three types: Fully pressurised, Semi-pressurised & semi/fully refrigerated and fully refrigerated ships (Eyres, 2007). The first two types are used to transport smaller quantities having capacities of 3500m^3 and 15000m^3 respectively (Eyres, 2007). Fully refrigerated are the most common types of LPG ships, which have large capacities varying between 15000m^3 and 85000m^3 (Eyres, 2007). These ships have a minimum working temperature of -50°C and maximum working pressure of 0.28 kg/cm^3 (Eyres, 2007). Ammonia is transported by fully refrigerated LPG ships, which have tanks that extend to the full length of the ship as to maximise usable space (Eyres, 2007). As seen in figure 13, the system components involved in the maritime shipping of ammonia includes the ammonia sold at the port of source, shipping of ammonia and storing the ammonia at the port of Rotterdam.

Figure 13: System boundaries for ammonia maritime shipping

44149 tons of ammonia have to be imported on a daily basis to satisfy the hydrogen demand in the Netherlands. Therefore, a fully refrigerated LPG ship which has a capacity of 80000m^3 is chosen to transport the ammonia over a distance of 8000km. A capacity of 80000m^3 can hold 54560 tons of ammonia, taking into account a density of 682 kg/m^3. Table 47 shows the parameters used for modelling maritime shipping of ammonia.

Table 47: Parameters used for ammonia shipping (Dobrota et al., 2013)(Polemis, 2013)(Rodrigue et al., 2017)(Rogers, 2018)(Eyres, 2007)

Parameter	Value	Unit
Capacity of ship	80000	m^3
Speed	19 (35)	knots (km/h)
Distance	8000	km
Boil-off losses	0.12	% per day
Heel	4	% of total capacity
Fuel consumption	30	tons/day
Time at port (source and destination)	3	days

Some of the parameters have been assumed to be similar to LNG shipping. The boil-off losses of 0.12% per day and a heel of 4% of the total capacity, results in a net capacity of 51757 tons of ammonia being delivered to the port of destination. For a daily demand of 44149 tons of ammonia, a ship has to be chartered every day, which would result in 365 trips being made on a yearly basis. The energy consumption for maritime shipping of ammonia includes the energy consumed for producing ammonia, fuel consumed during shipping and the energy consumed during storage at the port of Rotterdam. The energy consumed during storage at the port has already been estimated in section 7.3.2 which is 1964 MWh/day. The parameters to estimate the energy required for maritime shipping of ammonia is listed in table 48. The energy consumed by the maritime shipping of ammonia is shown in table 49

Table 48: Parameters used to estimate the energy consumed for ammonia shipping (Frattini et al., 2016)(Engineering Toolbox, 2003)

Parameter	Value	Unit
Energy required for production	14.3	$kW/kgNH_3$
Energy density of HFO	39000	MJ/tons

Table 49: Energy consumption of ammonia shipping

Production, MWh/day	Fuel consumption, MWh/day	Liquid storage, MWh/day	Total, MWh/day
737439	4054	1663	743156

It is evident from table 49, that the energy consumption is dominated by production of ammonia while shipping and storage of ammonia contribute to less than 10% of the energy consumed.

7.3.4 Pipeline transport

Currently, more than 4000 km of ammonia pipelines are operating in the USA alone, which shows the maturity of the ammonia pipeline infrastructure (Bartels, 2008). As seen in figure 14, the transport of ammonia by pipelines involves: hydrogen production, ammonia production with storage, ammonia imports with storage, loading and unloading, transport by pipeline, ammonia storage at the destination and ammonia reforming.

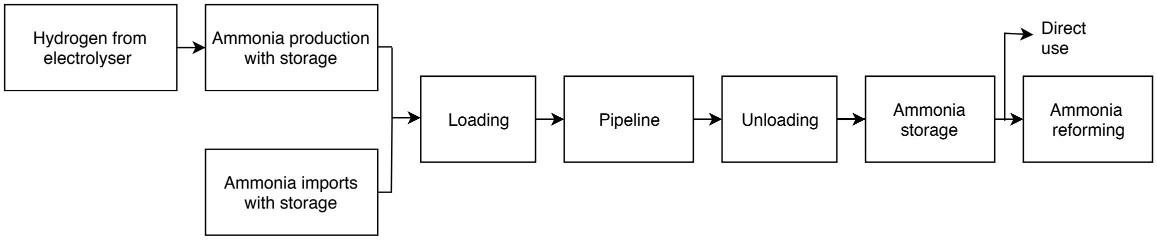

Figure 14: System boundaries for ammonia pipeline transport

Ammonia is transported through carbon steel pipelines usually at around 100 bar (Bartels, 2008). The high pressure reduces the need for additional compressor stations in between the routes unless very long pipelines are laid. Since ammonia is transported as a liquid, the transport velocity is to be restricted between 5 - 20 m/s as per NORSOK standards (Knoppe, 2015). The parameters used to model the ammonia pipelines is shown in table 50.

Table 50: Ammonia pipeline design parameters (Sashi Menon, 2005)(Knoppe, 2015)(T. Lipman & Shah, 2007)

Parameter	**Value**	**Unit**
Inlet pressure in the pipeline	10	MPa
Design factor	0.5	
Roughness factor	0.00002	m
Base pressure of the pipeline	0.101	MPa
Base temperature of the pipeline	288	K
Density of steel	7900	kg/m^3
Corrosion allowance	0.001	m
Molecular mass	0.017	kg/mol
Gas gravity	0.618	
Average temperature	288	K
Density of ammonia	618	kg/m3
Specific heat	1.12	
Kinematic viscosity	0.2186	cSt

The pipeline is designed as per the flowchart shown in figure 5. Using the parameters listed in table 50, the ammonia pipelines are modelled, which is shown in table 51. Similar to hydrogen pipelines, steel grade x65 came out to be the most economical in all the routes except for Delfzijl to Emmen, in which x70 is the more economical option.

Route	Amount, tons/day	Distance, km	Steel grade	Thickness, m	Outer diameter, m	NPS	Cost of pipeline, M€
Delfzijl - Emmen	643	60.7	x42	0.004	0.14	5	1.06
			x52	0.0038	0.1412	5	0.90
			x65	0.0032	0.1413	5	0.86
			x70	0.0028	0.127	4.5	0.74
Delfzijl - Amsterdam	510	176	x42	0.0054	0.1684	6	4.23
			x52	0.0044	0.1683	6	3.54
			x65	0.0036	0.1683	6	3.35
			x70	0.0034	0.1683	6	3.45
Rotterdam - Amsterdam	8999	59.6	x42	0.0102	0.3556	14	5.79
			x52	0.0081	0.3555	14	4.73
			x65	0.0065	0.3556	14	4.33
			x70	0.0061	0.3557	14	4.42
Rotterdam - Zeeland	11468	63.3	x42	0.0115	0.4063	16	7.94
			x52	0.0092	0.4065	16	6.46
			x65	0.0073	0.4064	16	5.90
			x70	0.0068	0.4064	16	6.01
Rotterdam - Chemelot							
Rotterdam - Nijmegen	8362	81.1	x42	0.0102	0.3556	14	7.88
			x52	0.0081	0.3555	14	6.43
			x65	0.0065	0.3556	14	5.80
			x70	0.0061	0.3557	14	6.02
Nijmegen - Chemelot	8362	90.5	x42	0.0115	0.4063	16	11.35
			x52	0.0081	0.3555	14	7.18
			x65	0.0065	0.3556	14	6.58
			x70	0.0061	0.3557	14	6.72

Table 51: Ammonia pipeline design

To be able to transport ammonia at such high pressures, pumps are required. Table 52 show the pump capacities required for ammonia pipeline transport which was designed using equation 15. The suction pressure for the pumps is 0.1 MPa, which is the storage pressure of ammonia using low temperature storage. The parameters used for sizing the pumps have been listed in the bottom half of table 50, as similar parameters are used. It is assumed that pump capacities for loading and unloading are similar.

Table 52: Pump capacities for ammonia pipelines

Transport route	Pump capacity, kW	Discharge pressure, MPa
Delfzijl - Emmen	4091	10
Delfzijl - Amsterdam	3242	10
Rotterdam - Amsterdam	57223	10
Rotterdam - Zeeland	72922	10
Rotterdam - Chemelot	53175 + 30884	10

Similar to hydrogen pipelines, energy is only consumed by the pumps during the loading and unloading of ammonia onto and from the pipelines. Loading and unloading ammonia along all the transport routes is estimated to be 10634 MWh/day.

7.3.5 Road transport

Ammonia is transported as a liquid by T10-type tank containers which has a maximum weight of 20 tons and hydraulic capacity of 16415.2 litres (Botero, 2018). Ammonia can either be pressurised into liquid form by compressing it, to about 862 kPa or be refrigerated to -33°C (Papavinasam, 2014). In the case of T10-type tanks, ammonia is pressurised to 10 bar, at which point ammonia has a density of 609 kg/m^3. Taking into account the weight of the trailer and the cabin which is estimated to be 5 tons and 4 tons respectively, 11 tons of ammonia can be transported by the T10-type tank (Botero, 2018). It is to be noted that the hydraulic capacity of the truck which is based on water, further limits the amount of ammonia that can be transported as the volume available depends on the density of the liquid. If 11 tons of ammonia is to be transported, a hydraulic capacity of 18057 litres should be available. Since the tank container has a hydraulic capacity of 16415.2 litres, only 16415.2 litres which translates to 10 tons of ammonia can be transported by T10-type tank containers. Loading and unloading of the trucks are done using pumps which is assumed to take one hour each for loading and unloading at the source and destination.

The system boundaries for the transport of ammonia by road include: hydrogen production, ammonia production with storage, ammonia imports with storage, loading and unloading, transport by tank containers, ammonia storage at the destination and ammonia reforming. The system boundaries can be seen in figure 15.

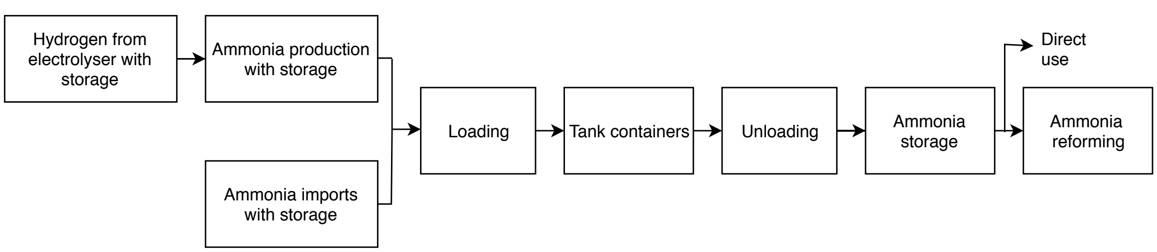

Figure 15: System boundaries for ammonia road transport

To model the transportation of ammonia by road, first the number of tank containers needed for each route has to be estimated. The parameters used to estimate the number of tank containers needed for each route is shown in table 53. Using these parameters, the number of tank containers required can be estimated, which is shown in table 54.

Table 53: Parameters used to estimate the number of tank containers needed (Yang & Ogden, 2007)(Wulf & Zapp, 2018)

Parameter	**Value**	**Unit**
Truck speed (average)	50	km/h
Fuel consumption	32	l/100km
Unloading and loading time	2	hrs

Table 54: Estimated number of tank containers needed

Route	**Amount of ammonia, tons/day**	**Distance, km**	**Time taken, hrs**	**No. of trips per day**	**No. of tank containers needed**
Delfzijl - Emmen	643	76	3.52	3	22
Delfzijl - Amsterdam	510	222	6.44	1	51
Rotterdam - Amsterdam	8999	75	3.5	3	301
Rotterdam - Zeeland	11468	83	3.66	3	383
Rotterdam - Chemelot	8362	179	5.58	2	419

To load and unload ammonia onto the T-10 tank containers, pumps have to be used. Table 56 shows the pump capacity required for ammonia road transport which was designed using equation 15. The parameters used to design the pumps are listed in table 55. The pump capacity for loading is assumed to be similar for unloading, and thereby pumps used for unloading ammonia at the destination will have the same capacity. Similar to hydrogen road transport, the number of pumps required was assumed to be equal to the number of tank containers needed for each route.

Table 55: Ammonia pump design data (T. Lipman & Shah, 2007)(Sashi Menon, 2005)

Parameter	**Value**	**Unit**
Molecular mass	0.017	kg/mol
Gas gravity	0.618	
Density of ammonia	609	kg/m3

Table 56: Pump capacity for ammonia road transport

Vehicle type	**Pump capacity, kW**	**Discharge pressure, MPa**
T-10 Tank containers	139	0.1

The energy consumed for the road transportation of ammonia includes loading, transportation and unloading of the ammonia at the destination. This is shown in table 57.

Table 57: Estimated energy consumption of ammonia road transport

Route	Fuel consumption litres/day	Energy consumption of tankcontainers, MWh/day	Loading and unloading, MWh/day
Delfzijl - Emmen	3210	31	146
Delfzijl - Amsterdam	7246	70	340
Rotterdam - Amsterdam	43344	420	2004
Rotterdam - Zeeland	61035	592	2550
Rotterdam - Chemelot	96001	931	2789
Total		2045	7829

As seen in the table, loading and unloading ammonia onto the tank containers consume more energy than the tank containers themselves. Therefore, the transport route does not affect the final energy consumption relative to the number of pumps and pump capacities required for road transport.

7.3.6 Energy efficiency of ammonia transport

The energy efficiency of ammonia transport systems are estimated as discussed in section 7.2.9, using formula 16. The energy efficiencies of the ammonia transport systems are listed in table 58.

Table 58: Energy efficiency of ammonia transport systems

Transport medium	Production, MWh/day	Storage, MWh/day	Transport medium, MWh/day	Reforming, MWh/day	Import, MWh/day	Total, MWh/day	Efficiency
Pipeline	286091	1767	10634	20930	743156	1062578	36%
Road	286091	1767	9874	20930	743156	1061820	36%

The energy efficiencies of both pipeline and road transport are the same as the system components for both are the same except for the transport medium. Compared to the energy spent for production and imports, the energy spent by the transport medium is almost negligible for both pipeline and road transport. Therefore at a system level, the energy efficiency is the same for pipeline and road transport of ammonia.

7.4 Methanol transport

Methanol, another energy carrier that was shortlisted, is a hydrocarbon unlike ammonia and thereby requires hydrogen and carbon as raw materials. The production of hydrogen has already been discussed in section 7.2.1, while carbon is assumed to be captured from the atmosphere in the form of CO_2, and not from flue gases or from biomass. It is assumed that there would not be many industries using fossil fuels by 2050 and thereby CO_2 emissions from flue gases becomes limited. CO_2 emissions from biomass comes with the assumption that there would be enough biomass available in the Netherlands by 2050, to generate as much as carbon required for methanol production, with the additional costs of either transporting the CO_2 or biomass to the methanol production site. To make sure the model is not complicated and dependent on several external factors, it was chosen to use captured CO_2 from the atmosphere. Direct Air Capture (DAC) systems capture the CO_2 necessary for methanol production from the atmosphere. M.Fasihi et.al, has reported that low temperature solid sorbent DAC systems are more likely to be cost-effective than high temperature aqueous solution DAC systems due to lower heat supply costs, which lowers CO_2 costs (Fasihi, Efimova, & Breyer, 2019). It is reported that CO_2 will have a cost of 222 €/tonCO_2 based on a hybrid PV-wind powered low temperature solid sorbent DAC system (Fasihi et al., 2019). In the same report, it also mentions that the costs of CO_2 varies anywhere between 75 to 900 €/tonCO_2, upon reviewing various other literature (Fasihi et al., 2019). Due to the variability of reported values in literature, it was assumed that CO_2 would be purchased at a price of 222 €/tonCO_2 based on M.Fasihi et.al's model (Fasihi et al., 2019).

Traditionally, methanol is produced using the Fisher-Tropsch process, where pressurised syngas reacts over a catalyst (Pérez-Fortes, Schöneberger, Boulamanti, & Tzimas, 2016). To produce methanol in a renewable manner, CO_2 becomes the dominant carbon compound in contrast to the dominant CO in syngas in the Fisher-Tropsch process. Therefore, the reaction equation varies slightly, which is shown below:

$$CO_2 + 3H_2 \rightleftharpoons CH_3OH + H_2O \tag{18}$$

The reactants are pressurised to the reactor pressure, heated and then passed over a catalyst for the reaction to take place. Methanol is then separated from water, which is a by-product of the reaction through a distillation column (Pérez-Fortes et al., 2016). Using the equation above, 1 ton of methanol would require 0.189 ton of hydrogen as reactants. Unlike ammonia, which only requires electricity for its production needs, methanol requires heat as well (Pérez-Fortes et al., 2016). This heat is assumed to be supplied by the hydrogen through hydrogen combustion in turbines, as to complement the renewable model adopted in this thesis. Thereby, more hydrogen will be consumed to produce the same amount of methanol. Perez-Fortes et.al, estimated the heat requirements to be 0.44 MWh/tonCH_3OH (Pérez-Fortes et al., 2016). Hydrogen has a calorific value of 141 MJ/kgH_2 and therefore, to be able to provide the heat necessary for the production of 1 ton of methanol, 0.011 tons of hydrogen would be required. This is estimated assuming that hydrogen gas turbines will have an efficiency of 60%, similar to natural gas turbines. Thereby to produce 1 ton of methanol, 0.2 tons of hydrogen would be required. Table 59 lists the parameters required to model the methanol production plants followed by table 60, which shows the methanol produced at each location. The parameters used to model the methanol production plants have been based on the papers by Perez-Fortes et.al, and M.Fasihi et.al (Pérez-Fortes et al., 2016)(Fasihi et al., 2019).

Table 59: Parameters used to model methanol production plants (Lensink & Pisca, 2019)(Fasihi et al., 2019)(Pérez-Fortes et al., 2016)

Parameter	**Value**	**Unit**
Density	792	kg/m^3
Electricity needed	1.031	MWh/tonCH_3OH
Heat needed	0.44	MWh/tonCH_3OH
Process efficiency	95	%
Operating capacity	80	%

Table 60: Methanol production in the Netherlands

Industrial cluster	Hydrogen production, tons/day	Methanol production, tons/day	Electricity demand, MWh/day	Heat demand, MWh/day
Rotterdam	1785	6771	6892	2973
Amsterdam	1648	6253	6447	2745
Delfzijl	571	2166	2233	951
Zeeland	603	2288	2359	1004
Total		17478		

The amount of hydrogen combusted to generate heat for methanol production is 119 ktons per year. This loss of hydrogen has to be compensated through increased imports from abroad.

7.4.1 Methanol reforming

To estimate the mismatch in the supply and demand for methanol in each industrial cluster, the demand for methanol has to be estimated for each industrial cluster based on the demand for hydrogen. Methanol reforming is a process in which, methanol is converted back to hydrogen. Steam reforming using a packed bed reactor is the most common method of methanol reforming while other methods like autothermal reforming of methanol uses higher temperatures and thereby incurs higher costs. Steam reforming of methanol using membrane reactors have been researched into over the past few years and is proven to be more efficient with higher yields of hydrogen compared to packed bed reactors, but is yet to be commercially implemented on a large-scale (Kim et al., 2019). Therefore in this thesis, steam reforming of methanol using packed bed reactors will be modelled. Varying process efficiencies from 40 to 60% have been reported depending on the modification of the technology used for the reaction (Kim et al., 2019)(Chen et al., 2018). An efficiency of 50% has been used for methanol steam reforming in this thesis. With this efficiency, the demand for methanol can be estimated, which is shown in table 61.

Table 61: Methanol demand in the Netherlands

Industrial cluster	Hydrogen demand, tons/day	Methanol demand, tons/day
Rotterdam	3095	32724
Amsterdam	2197	23236
Delfzijl	128	1355
Zeeland	1941	20525
Chemelot	1190	12586
Emmen	91	968
Total		91395

With the estimated supply and demand for methanol, the amount of methanol that will have to imported is estimated to be 73917 tons per day. The quantity of methanol that would have to be transported across the six industrial clusters in the Netherlands is estimated and shown in table 62.

Table 62: Methanol transported along each route in the Netherlands

Transport routes	**Amount of methanol, tons/day**
Delfzijl - Emmen	810
Rotterdam - Emmen	158
Rotterdam - Amsterdam	16983
Rotterdam - Zeeland	18237
Rotterdam - Chemelot	12586

It can be noticed that the extra consumption of hydrogen for the methanol production process, has resulted in the change of the transport routes across the six industrial clusters. For hydrogen and ammonia transport, the Emmen industrial cluster could solely be supplied by the surplus from Delfzijl, but for methanol this is not the case. Rotterdam has to supplement this by transporting methanol to Emmen as well, this changes the transport network as the Delfzijl to Amsterdam route is no longer available and Rotterdam to Delfzijl is added.

Steam reforming of methanol requires heat and electricity to power the process. As discussed for ammonia reformers and also for methanol production, hydrogen can be combusted to provide the heat needed for the process. Table 63 shows the parameters used to model the methanol reforming plants. Modelling of the methanol reformer plant has been based on a small stationary methanol reformer as large commercial plants are scarce. The reformer is based on Kim et.al,'s paper on a 288kg/day methanol reformer (Kim et al., 2019).

Table 63: Parameters used for modelling methanol steam reforming plants (Kim et al., 2019)(van Wijk, 2018)

Parameter	**Value**	**Unit**
Process efficiency	50	%
Electricity required	240	kWh/day
Heat required	515	kWh/day
Hydrogen combustion efficiency	60	%
Hydrogen energy density	141	MJ/kg

Using the parameters listed, table 64 shows the methanol reformer plant capacities at each industrial cluster alongside the electricity and heat demands. As discussed during ammonia reforming, only 96 PJ of hydrogen is required for non-energy applications. Thereby the methanol reformer plants have been modelled to produce this which also includes the hydrogen combusted in the process.

Table 64: Methanol reformers at the six industrial clusters

Industrial cluster	**Methanol reformer capacity, tons/day**	**Electricity demand, MWh/day**	**Heat demand, MWh/day**	**Hydrogen combusted, tons/day**
Rotterdam	7075	557	1196	51
Amsterdam	5024	396	849	36
Delfzijl	293	23	50	2
Zeeland	4438	350	750	32
Chemelot	2721	214	460	20
Emmen	209	16	35	2

7.4.2 Methanol storage

The fact that methanol is a liquid at room temperature, allows it to be easily stored in tanks that store diesel or gasoline. Existing storage tanks of diesel and gasoline can be adapted to hold methanol after cleaning the tanks (EA Engineering Science and Technology Inc, 1999)(Jackson & Ward, 2014). Storage tanks for methanol are maintained, at 1 atm and ambient temperature but the low conductivity of methanol requires the tanks to be placed directly on the ground or underground [5] (EA Engineering Science and Technology Inc, 1999)(Jackson & Ward, 2014). Table 65 shows the storage tank capacities needed at the source and destination. Energy consumption is assumed to negligible in the case of methanol storage, as methanol does not need to be liquefied or pressurised to be stored as a liquid. Therefore, pumps to re-liquefy or pressurise methanol are not used in the storage tanks unlike ammonia storage. Storage is also assumed to be momentary, which means that the methanol in the storage tank is assumed to be completely consumed by the end of the day.

Table 65: Methanol storage capacity

Industrial cluster	**Storage capacity at the source, tons/day**	**Storage capacity at the port, tons/day**	**Storage capacity at destination, tons/day**
Rotterdam	6772	121651	-
Amsterdam	6254	-	16983
Delfzijl	2166	-	-
Zeeland	2288	-	18238
Chemelot	2288	-	12587
Emmen	2288	-	969

7.4.3 Maritime shipping

Methanol is transported by special ships that have tanks made from stainless steel or zinc (Grover, 2013). Unlike hydrogen and ammonia, methanol ships are not refrigerated as methanol is a liquid at room temperature. As seen in figure 16, the system components involved in the maritime shipping of methanol includes the methanol sold at the port of source, shipping of methanol and storing methanol at the port of destination - port of Rotterdam.

Figure 16: System boundaries for methanol maritime shipping

The ship that has been modelled in this thesis to transport methanol, has a capacity of 80000m^3 as it is currently the largest methanol carrying ship in service (Vestereng, 2017). With a density of 792 kg/m^3, 63360 tons of methanol can be transported per trip in this tanker. Assuming that a heel of 4% is kept in the tanks after unloading the methanol, the net tonnage of methanol transport is 60826 tons of methanol. Table 66 shows the parameters used for modelling maritime shipping of methanol.

[5] Underground tanks are usually placed a few feet below the ground

Table 66: Parameters used for methanol shipping (Dobrota et al., 2013)(Polemis, 2013)(Rodrigue et al., 2017)(Rogers, 2018)(Eyres, 2007)

Parameter	Value	Unit
Capacity of ship	80000	m^3
Speed	19 (35)	knots (km/h)
Distance	8000	km
Heel	4	% of total capacity
Fuel consumption	30	tons/day
Time at port (source and destination)	3	days

73916 tons of methanol have to be imported on a daily basis to be able to satisfy the demand in the Netherlands. Since only 60826 tons of methanol can be transported in a single trip, two ships will have to be chartered every day for 365 days a year, resulting in 730 trips on a yearly basis. The energy consumption for maritime shipping of methanol includes the energy consumed for producing methanol, fuel consumed during shipping and the energy consumed during storage at the port of Rotterdam. The energy consumed by methanol storage is assumed to be negligible and thereby can be eliminated. The parameters used to estimate the energy required for maritime shipping of methanol is listed in table 67 followed by the energy consumed by the maritime shipping of methanol shown in table 68.

Table 67: Parameters used to estimate the energy consumed for methanol shipping (Fasihi et al., 2019)(Pérez-Fortes et al., 2016)(Engineering Toolbox, 2003)

Parameter	Value	Unit
Energy required for production	17.2	MWh/tonCH_3OH
Energy density of HFO	39000	MJ/tons

Table 68: Estimated energy consumption for methanol shipping

Production, MWh/day	Fuel consumption, MWh/day	Storage, MWh/day	Total, MWh/day
1271761	8107	-	1279868

Methanol shipping follows the same trend as ammonia and hydrogen shipping, wherein the energy consumed for producing the energy carrier consumes most of the energy, compared to the other components within the system.

7.4.4 Pipeline transport

Currently, only short distance methanol pipelines exist from and to storage tanks, factories and jetties (Bechtold, Goodman, & Timbario, 2007). Carbon steel grade pipelines are used for transporting methanol similar to most other chemicals transported by pipeline (Bechtold et al., 2007). The corrosive nature of methanol, makes methanol a chemical that has to be handled with care during transportation (Bechtold et al., 2007). The system boundaries for pipeline transport of methanol is similar to that of ammonia pipeline transport. The system components include the production of hydrogen, methanol production with storage, methanol imports with storage, loading, pipeline transport, unloading, methanol storage and methanol reforming. The system boundary is depicted in figure 17.

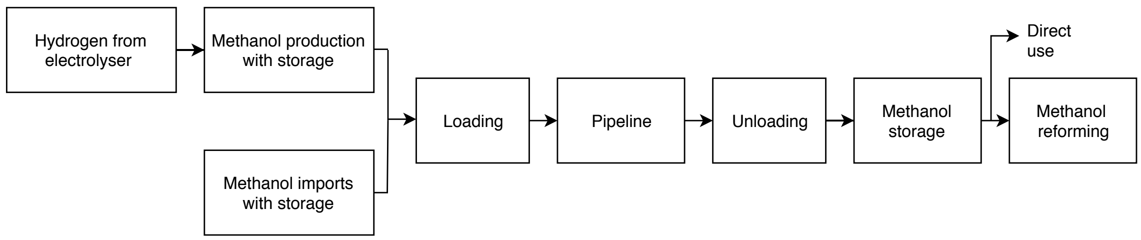

Figure 17: System boundaries for methanol pipeline transport

Specific transport pressures could not be found in the case of methanol transport and thereby is modelled after ammonia pipeline transport, which has an inlet pressure of 100 bar. Similar to ammonia pipeline transport, the velocity of methanol in the pipeline will be limited between 5 - 20 m/s as per NORSOK standards. The parameters used to model methanol pipeline transport is listed in table 69.

Table 69: Methanol pipeline design parameters (Sashi Menon, 2005)(Knoppe, 2015)

Parameter	**Value**	**Unit**
Inlet pressure in the pipeline	10	MPa
Design factor	0.5	
Roughness factor	0.00002	m
Base pressure of the pipeline	0.101	MPa
Base temperature of the pipeline	288	K
Density of steel	7900	kg/m^3
Corrosion allowance	0.001	m
Molecular mass	0.032	kg/mol
Gas gravity	0.7915	
Average temperature	288	K
Density of methanol	792	kg/m3
Specific heat	1.20	
Kinematic viscosity	0.7915	cSt

Using the design parameters, the methanol pipelines were modelled and is shown in table 70. As seen in the table, the transport routes have changed compared to hydrogen and ammonia. Rotterdam becomes the main supplier of methanol to all the industrial clusters with Delfzijl only being able to supply a portion of the demand in Emmen. The transport route from Rotterdam to Nijmegen carries the amount of methanol destined for both Chemelot and Emmen. At Nijmegen, compressor stations were used to pump the required amounts in the separate transport routes: Nijmegen - Chemelot and Nijmegen - Emmen. Analysing all the routes, the most economical pipeline steel grade for methanol transport is the steel grade x65 for all routes.

Table 70: Methanol pipeline design

Route	**Amount, tons/day**	**Distance, km**	**Steel grade**	**Thickness, m**	**Outer diameter, m**	**NPS**	**Cost of pipeline, M€**
Delfzijl - Emmen	810	60.7	x42	0.0054	0.1684	6	1.46
			x52	0.0044	0.1683	6	1.22
			x65	0.0036	0.1683	6	1.15
			x70	0.0034	0.1683	6	1.19
Rotterdam - Amsterdam	16983	59.6	x42	0.0128	0.4569	18	9.36
			x52	0.0102	0.457	18	7.60
			x65	0.0081	0.457	18	6.92
			x70	0.0075	0.457	18	7.04
Rotterdam - Zeeland	18237	63.3	x42	0.0128	0.4569	18	9.94
			x52	0.0102	0.457	18	8.07
			x65	0.0081	0.457	18	7.35
			x70	0.0075	0.457	18	7.48
Rotterdam - Nijmegen	12744	81.1	x42	0.0128	0.4569	18	12.74
			x52	0.0102	0.457	18	10.34
			x65	0.0073	0.4064	17	7.56
			x70	0.0068	0.4064	17	7.70
Nijmegen - Chemelot	12586	90.5	x42	0.0127	0.4567	18	14.22
			x52	0.0102	0.457	18	11.54
			x65	0.0081	0.457	18	10.51
			x70	0.0075	0.457	18	10.70
Nijmegen - Emmen	158	139	x42	0.0036	0.1015	3.5	1.36
			x52	0.003	0.1015	3.5	1.17
			x65	0.0026	0.1017	3.5	1.13
			x70	0.0024	0.1015	3.5	1.18

Pumps are required to pressurise and transport methanol at a transport pressure of 10MPa. Table 71 shows the pump capacities required for methanol pipeline transport, which was designed using equation 15. The suction pressure for the pumps is 0.1 MPa, which is the storage pressure of methanol in the methanol storage tanks. The parameters used for modelling the pumps have been listed in the bottom half of table 69, as similar parameters are used. It is assumed that pump capacities for loading and unloading are similar.

Table 71: Pump capacities for methanol pipelines

Transport route	Pump capacity, kW	Discharge pressure, MPa
Delfzijl - Emmen	4023	10
Rotterdam - Amsterdam	84321	10
Rotterdam - Zeeland	90550	10
Rotterdam - Nijmegen	62493	10
Nijmegen - Chemelot	42859	10
Nijmegen - Emmen	537	10

Similar to hydrogen and ammonia pipelines, energy is only consumed by the pumps during the loading and unloading of methanol onto and from the pipelines. Loading and unloading methanol along all the transport routes is estimated to be 136670 MWh/day.

7.4.5 Road transport

Unlike hydrogen and ammonia, methanol is a liquid under standard conditions and thereby can only be transported as a liquid by road. Methanol is transported by steel road tankers which is used to also transport many other chemicals (Botero, 2018). The steel tanker chosen for this thesis, is a 40 ton tanker which has a net weight of 25 tons, after deducting the semi-trailer and cabin weights of 6 and 9 tons respectively (Botero, 2018). At 25 tons, 31566 litres of methanol can be transported, using a density of 792 kg/m^3. The tanker has a hydraulic capacity of 26000 litres, which is lower than the volume of methanol estimated for the same mass (Botero, 2018). Thereby only 26000 litres of methanol can be transported in one 40 ton methanol steel tanker. Loading and unloading of the methanol onto and from the tanker is done using pumps and is assumed to take one hour each. Similar to methanol pipelines, the road transport of methanol has the same components except for the transport medium, as seen in figure 18.

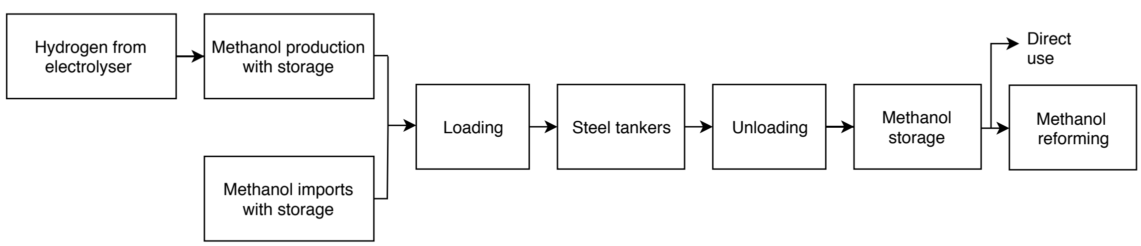

Figure 18: System boundaries for methanol road transport

To model the transportation of methanol by road, first the number of steel tankers needed for each route was estimated, which is shown in table 73. The parameters used to estimate the number of steel tankers needed for each route is shown in table 72. The loading and unloading time is assumed to be one hour each similar to ammonia road transport.

Table 72: Parameters used to estimate the number of tankers needed (Yang & Ogden, 2007)(Wulf & Zapp, 2018)

Parameter	**Value**	**Unit**
Truck speed (average)	50	km/h
Fuel consumption	32	l/100km
Unloading and loading time	2	hrs

Table 73: Estimated number of steel tankers needed for each route

Route	**Amount of methanol, tons/day**	**Distance, km**	**Time taken, hrs**	**No. of trips per day**	**No. of steel tankers needed**
Delfzijl - Emmen	810	76	3.52	3	14
Rotterdam - Emmen	158	223	6.46	1	8
Rotterdam - Amsterdam	16983	75	3.5	3	275
Rotterdam - Zeeland	18237	83	3.66	3	296
Rotterdam - Chemelot	12586	179	5.58	2	306

Pumps for loading and unloading methanol onto the steel tankers are modelled using equation 15. The capacity of the pumps modelled, are shown in table 75 with the parameters used to model the pump listed in table 74. Pump capacities for unloading the steel tankers at the destination is assumed to be similar to loading the tankers at the source. Also the number of pumps required for each route is assumed to be equal to the number of steel tankers needed for each route.

Table 74: Methanol pump design data (Sashi Menon, 2005)

Parameter	**Value**	**Unit**
Molecular mass	0.032	kg/mol
Gas gravity	0.7915	
Density of methanol	792	kg/m3

Table 75: Pump capacity for methanol road transport

Vehicle type	**Pump capacity, kW**	**Discharge pressure, MPa**
Steel tankers	223	0.1

The energy used for the road transportation of methanol includes loading of the methanol onto the tanker, transportation and unloading of the methanol at the destination. The estimated energy usage is shown in table 76.

Table 76: Estimated energy consumption of methanol road transport

Route	**Fuel consumption litres/day**	**Energy consumption of steel tankers, MWh/day**	**Loading and unloading, MWh/day**
Delfzijl - Emmen	2043	20	150
Rotterdam - Emmen	1142	110	86
Rotterdam - Amsterdam	39600	384	2944
Rotterdam - Zeeland	47171	458	3168
Rotterdam - Chemelot	70111	680	3275
Total		1553	9623

Similar to ammonia, the pumps used for loading and unloading the steel tankers consume more than 5 times the energy required as fuel for the tanker This further strengthens the argument, that even when the transport route has changed, the tankers still do not consume as much energy as loading and unloading the tanker.

7.4.6 Energy efficiency of methanol transport

The energy efficiency of methanol transport is estimated using formula 16, and the energy breakdown with the final estimated efficiency is shown in table 77.

Table 77: Energy efficiency of methanol transport systems

Transport medium	**Production, MWh/day**	**Storage, MWh/day**	**Transport medium, MWh/day**	**Reforming, MWh/day**	**Import, MWh/day**	**Total, MWh/day**	**Efficiency**
Pipeline	300733	-	13670	4896	1279868	1599167	37%
Road	300733	-	11176	4896	1279868	1596673	37%

Similar to ammonia, pipeline and road transport have similar energy efficiencies, as the transport modes consume very less energy compared to production and import. Methanol has a lower efficiency compared to ammonia, as methanol production consumes more energy relative to ammonia production. Therefore import and production energy consumption is higher for methanol compared to ammonia.

7.5 DME transport

Dimethyl Ether (DME), a derivative of methanol, is another shortlisted energy carrier in this thesis. Since DME is a derivative of methanol, industries use methanol as feedstock for DME production in a two step process (Kiss et al., 2013). DME can also be produced directly from syngas in a one step process with the production of methanol as an intermediate. This method of producing DME has been implemented by a few small-scale industries like BioDME in Sweden (Hankin & Shah, 2017)(Michailos, McCord, Sick, Stokes, & Styring, 2019)(Anon, 2011). The small scale production of DME using the one step production process, makes availability of data of the process more difficult to obtain as compared to the two step process. In this situation, it was decided to use the two step process to produce DME, as information is more readily available. The two step process involves production of methanol in the first step followed by methanol dehydration in the second step to produce DME. Since methanol production has already been discussed in section 7.4, only the second step of the process (methanol dehydration) has to be modelled in this section. The reaction equation for methanol dehydration is shown below:

$$2CH_3OH \rightleftharpoons CH_3OCH_3 + H_2O \tag{19}$$

The methanol dehydration process usually takes place in a fixed bed catalytic reactor at pressures of 20 bar within a temperature range of 200 - 400°C (Kiss et al., 2013). Pure DME is produced with a process efficiency, varying usually between 70 - 80 % and is separated from water and the unreacted methanol in a distillation column (Kiss et al., 2013). Kiss A et.al, reports that a methanol dehydration unit using a dividing wall column would require 322 kWh of energy to produce one ton of DME (Kiss et al., 2013). Using the equation above, one ton of methanol can be used to produce 0.72 tons of DME. Table 78 lists the parameters used to model the methanol dehydration plant followed by table 79, which shows the quantity of DME that can be produced in the Netherlands. The methanol dehydration plant has been modelled after the methanol dehydration unit discussed in Kiss A et.al,'s paper (Kiss et al., 2013).

Table 78: Parameters used for modelling DME production plants (Michailos et al., 2019)(Kiss et al., 2013)

Parameter	**Value**	**Unit**
Density	735.2	kg/m^3
Electricity needed	322.2	kWh/tonCH_3OCH_3
Process efficiency	75	%
Operating capacity	80	%

Table 79: DME production in the Netherlands

Industrial cluster	**Methanol production, tons/day**	**DME production, tons/day**	**Electricity demand, MWh/day**
Rotterdam	6771	2921	941
Amsterdam	6253	2697	869
Delfzijl	2166	934	301
Zeeland	2288	987	318
Total		7539	

A total of 7539 tons of DME can be produced in the Netherlands on a daily basis from the dehydration of 17478 tons of methanol.

7.5.1 DME reforming

To estimate the demand for DME at each industrial cluster, which is based on the hydrogen demand, the reforming of DME to produce hydrogen has to be modelled. Similar to methanol, hydrogen is produced from DME by steam reforming of DME at a low temperature range of 200 - 350 °C (Rostrup-Nielsen & Hansen, 2011)(Elewuwa & Makkawi, 2015). Steam reforming of DME is similar to the steam reforming of methanol except with an intermediate step of DME hydrolysis to produce methanol, afterwhich the steam reforming of methanol produces hydrogen and carbon dioxide as seen in the equation below (Elewuwa & Makkawi, 2015).

$$CH_3OCH_3 + H_2O \rightleftharpoons 2CO_2 + 6H_2 \tag{20}$$

The similarity of the processes gives the freedom to model the process of steam reforming of DME after the steam reforming of methanol (Rostrup-Nielsen & Hansen, 2011). Similar to methanol, the steam reforming of DME also has efficiencies varying around 50% and therefore 50 % efficiency is assumed for this process. The estimated demand for DME at each industrial cluster is estimated and shown in table 80.

Table 80: Demand for DME in the Netherlands

Industrial cluster	**Hydrogen demand, tons/day**	**DME demand, tons/day**
Rotterdam	3095	23527
Amsterdam	2197	16705
Delfzijl	128	974
Zeeland	1941	14756
Chemelot	1190	9049
Emmen	91	696
Total		65708

With a demand of 65708 tons and production of 7539 tons, 58169 tons of DME has to be imported every day through the port of Rotterdam. The quantity of DME that needs to be transport across the Netherlands was estimated based on the imbalance amongst the clusters, which is shown in table 81.

Table 81: DME transported along each route in the Netherlands

Transport routes	**Amount of DME, tons/day**
Rotterdam - Delfzijl	40
Rotterdam - Emmen	696
Rotterdam - Amsterdam	14008
Rotterdam - Zeeland	13770
Rotterdam - Chemelot	9049

Similar to methanol transport, the transport routes have changed with respect to hydrogen and ammonia. This is expected as DME produced is a function of methanol and methanol itself has a different transport network with respect to hydrogen and ammonia. In the case of DME transport, the Delfzijl industrial cluster of is no longer self-sufficient to satisfy its own demand. Therefore, the industrial cluster in Rotterdam becomes the only supplier of DME to the rest of the industrial clusters including Delfzijl.

Steam reforming of DME requires both heat and electricity to power the process. As discussed for ammonia reformers, methanol production and methanol reformers, hydrogen can be combusted to provide the heat source needed for the process. Since the steam reforming of DME is similar to the steam reforming of methanol, the reformer modelled here are based on the reformer model proposed by Kim et.al, (Kim et al., 2019). The parameters used to model the DME steam reformers can be found in the methanol reforming section in table 63. Using the parameters listed, table 82 shows the DME reformer plant capacities at each industrial cluster alongside the electricity and heat demands, and the quantity of hydrogen combusted.

Table 82: DME reformers at the six industrial clusters

Industrial cluster	DME reformer capacity, tons/day	Electricity demand, MWh/day	Heat demand, MWh/day	Hydrogen combusted, tons/day
Rotterdam	5087	557	1196	51
Amsterdam	3612	396	849	36
Delfzijl	211	23	50	2
Zeeland	3191	350	750	32
Chemelot	1956	214	460	20
Emmen	150	16	35	2

7.5.2 DME storage

Like ammonia, DME is a gas at room temperature and thereby the DME is stored as a liquid after cooling (Irvine, 2016). Therefore, DME is stored in low-temperature storage tanks, which are maintained at -25°C to make sure DME is in its liquid form at all times (Irvine, 2016). In this thesis, low-temperature DME storage tanks are used after the DME production plant at the source, at the port for the ship to unload and at the destination before the DME is reformed back to hydrogen. In the case that liquid DME absorbs heat and turns into a gas, pumps are employed to re-liquefy the gaseous DME, which is the same case for low-temperature ammonia storage. Bartel et.al, has estimated the energy used for low- temperature ammonia storage to be 0.038 kWh/kgNH_3, which includes energy for the pumps for re-liquefaction and also to lower the temperature of ammonia output from the production plant to bring it to a liquid state (Bartels, 2008). In the case of DME, energy is only needed for the pumps as DME produced from the plant is already a liquid at -40°C. Bartel et.al, has estimated the energy required by the pumps for re-liquefaction to be 0.032 kWh/kgNH_3 (Bartels, 2008). Since the freezing point of ammonia and DME differ just by 8°C, it is assumed that the energy used by the pumps for re-liquefaction for low-temperature DME storage is the same as low-temperature ammonia storage, which is 0.032 kWh/kgNH_3. Table 83 and 84 shows the storage tank capacities needed at the source and destination with the energy required for each.

Table 83: DME storage capacity at the source

Industrial cluster	Storage capacity at the source, tons/day	Energy use, MWh/day	Storage capacity at the port, tons/day	Energy use, MWh/day
Rotterdam	2921	94	59287	1900
Amsterdam	2697	87	-	-
Delfzijl	934	30	-	-
Zeeland	987	32	-	-

Table 84: DME storage capacity at the destination

Industrial cluster	Storage capacity at destination, tons/day	Energy use, MWh/day
Delfzijl	41	1
Emmen	697	22
Amsterdam	14008	450
Zeeland	13770	442
Chemelot	9049	291

7.5.3 Maritime shipping

As mentioned earlier, the similarity between DME and LPG allows DME to be transported using LPG infrastructure. LPG ships have a minimum working temperature of -50°C, which allows DME to be transported as a liquid as the boiling point of DME is at -25°C (Eyres, 2007)(Irvine, 2016). LPG ships have been discussed in detail in section 7.3.3. The system boundaries for transporting DME by ship can be seen in figure 19. The system boundaries are similar to the maritime shipping of other energy carriers, which include the DME sold at the port of source, shipping of DME and DME storage at the port of destination - port of Rotterdam.

Figure 19: System boundaries for DME ship transport

DME is transported by fully refrigerated LPG ships, which have tanks that extend to the full length of the ship as to maximized usable space (Eyres, 2007). 58168 tons of DME have to be imported on a daily basis to satisfy the hydrogen demand. Therefore, a ship which has a capacity of 84000m^3 is chosen to transport DME over a distance of 8000km. A capacity of 84000m^3 can hold 61757 tons of DME, taking into account a density of 735.2 kg/m^3. Table 85 shows the parameters used for modelling maritime shipping of DME.

Table 85: Parameters used for DME shipping (Dobrota et al., 2013)(Polemis, 2013)(Rodrigue et al., 2017)(Rogers, 2018)(Eyres, 2007)

Parameter	Value	Unit
Capacity of ship	84000	m^3
Speed	19 (35)	knots (km/h)
Distance	8000	km
Boil-off losses	0.12	% per day
Heel	4	% of total capacity
Fuel consumption	48	tons/day
Time at port (source and destination)	3	days

A net capacity of 58585 tons of DME is delivered to the port of Rotterdam using a 84000m^3 LPG tanker taking into account boil-off losses of 702 tons per trip and a heel of 2470 tons. For a daily demand of 58168 tons of DME, one ship has to be chartered every day, which results in 365 trips being made on a yearly basis. The energy consumed for the maritime shipping of DME includes the energy consumed for producing DME at the port of source, fuel consumed during shipping and the energy consumed during storage at the port of Rotterdam. The energy consumed during storage at the port has already been estimated in section 7.5.2 which is 1905 kWh/day. The parameters used to estimate the energy required for maritime shipping of DME is listed in table 86, followed by the estimated energy consumption which is shown in table 87.

Table 86: Parameters used to estimate the energy consumed for DME shipping (Kiss et al., 2013)(Pérez-Fortes et al., 2016)(Engineering Toolbox, 2003)

Parameter	**Value**	**Unit**
Energy required for production	17.5	MWh/tonDME
Energy density of HFO	39000	MJ/tons

Table 87: Energy consumption of DME shipping

Production, MWh/day	**Fuel consumption, MWh/day**	**Liquid storage, MWh/day**	**Total, MWh/day**
1881915	4054	1900	1880759

The energy consumed for the production of DME dominates the total energy consumption for shipping, which is in line with the maritime shipping of the other energy carriers.

7.5.4 Pipeline transport

Currently, there is not much information available about DME pipeline transport. The similarity between the properties of LPG and DME, make it possible for DME to be transported using LPG infrastructure or ammonia infrastructure which also has similarities to LPG (Anon, 2011). Therefore in this thesis, DME pipelines were modelled after the ammonia pipelines modelled in section 7.3.4. As seen in figure 20, the system boundaries for the transport of DME by pipelines involves: hydrogen production, methanol production, DME production with storage, DME imports with storage at the port of Rotterdam, loading and unloading of DME, transport by pipeline, DME storage and reforming at the destination.

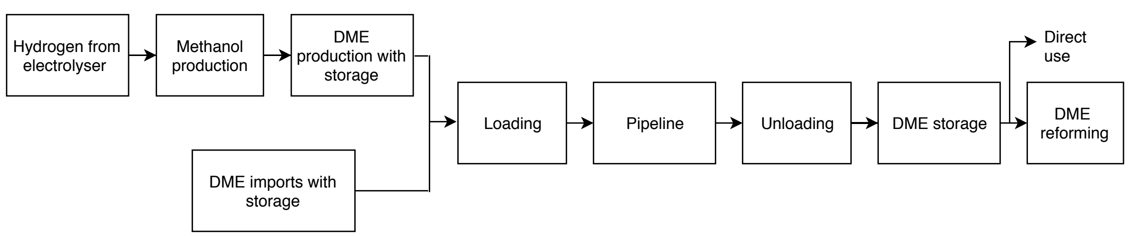

Figure 20: System boundaries for DME pipeline transport

DME is transported through carbon steel grade pipelines with an inlet pressure of 100 bar similar to ammonia. As discussed with the pipeline transport of ammonia and methanol, the velocity of DME in the pipeline will be limited between 5 - 20 m/s as per NORSOK standards. The parameters used to model DME pipeline transport is listed in table 88.

Table 88: DME pipeline design parameters (Sashi Menon, 2005)(Knoppe, 2015)(Ihmels & Lemmon, 2007)(Irvine, 2016)

Parameter	**Value**	**Unit**
Inlet pressure in the pipeline	10	MPa
Design factor	0.5	
Roughness factor	0.00002	m
Base pressure of the pipeline	0.101	MPa
Base temperature of the pipeline	288	K
Density of steel	7900	kg/m^3
Corrosion allowance	0.001	m
Molecular mass	0.046	kg/mol
Gas gravity	0.724	
Average temperature	288	K
Density of DME	686	kg/m3
Specific heat	1.1456	
Kinematic viscosity	0.26	cSt

Using the design parameters, the DME pipelines were modelled and is shown in table 89. As seen in table 89 and also discussed in the earlier section, the transport routes have changed even further when compared to methanol. The Rotterdam industrial cluster becomes the main distribution point in the case of DME transport. The transport route Rotterdam to Amsterdam, transports the combined quantity required both by Amsterdam and Delfzijl, from which the pipeline Amsterdam to Delfzijl only transports what is required by Delfzijl. This way of transporting DME was chosen, as the alternative route of transporting DME via Nijmegen to Emmen and then to Delfzijl, was longer. Similar to methanol, the transport route from Rotterdam to Nijmegen carries the quantity of DME destined for both Chemelot and Emmen. At Nijmegen, compressor stations were used to pump the required quantities into the separate transport routes: Nijmegen - Chemelot and Nijmegen - Emmen. Analysing all the routes, the most economical pipeline steel grade for DME transport was the steel grade x65, for all routes except for Amsterdam to Delfzijl. This route transports a very small amount of DME, thereby requiring smaller pipelines to be erected for which the carbon steel grade x52 is the more economical.

Table 89: DME pipeline design

Route	Amount, tons/day	Distance, km	Steel grade	Thickness, m	Outer diameter, m	NPS	Cost of pipeline, M€
Rotterdam - Amsterdam	14048	59.6	x42	0.0115	0.4063	16	7.47
			x52	0.0092	0.4065	16	6.08
			x65	0.0073	0.4064	16	5.55
			x70	0.0068	0.4064	16	5.66
Amsterdam - Delfzijl	40	176	x42	0.0026	0.0604	2	0.72
			x52	0.0022	0.0603	2	0.63
			x65	0.002	0.0604	2	0.64
			x70	0.0019	0.0604	2	0.67
Rotterdam - Zeeland	13770	63.3	x42	0.0115	0.4063	16	7.98
			x52	0.0092	0.4065	16	6.46
			x65	0.0073	0.4064	16	5.90
			x70	0.0068	0.4064	16	6.01
Rotterdam - Nijmegen	9745	81.1	x42	0.0115	0.4063	16	10.17
			x52	0.0081	0.3555	14	6.43
			x65	0.0065	0.3556	14	5.90
			x70	0.0061	0.3557	14	6.02
Nijmegen - Chemelot	9049	90.5	x42	0.0115	0.4063	16	11.13
			x52	0.0081	0.3555	14	7.18
			x65	0.0065	0.3556	14	6.58
			x70	0.0061	0.3557	14	6.72
Nijmegen - Emmen	696	139	x42	0.0054	0.1684	6	3.34
			x52	0.0044	0.1683	6	2.80
			x65	0.0036	0.1683	6	2.64
			x70	0.0034	0.1683	6	2.73

To transport DME at a pressure of 10MPa, pumps are used to pressurise DME and provide the kinetic energy required to transport it along the pipeline. Table 90 shows the pump capacities required for DME pipeline transport which was designed using equation 15. The suction pressure for the pumps is 0.1 MPa, which is the storage pressure of DME using low-temperature storage. The parameters used for sizing the pumps have been listed in the bottom half of table 88, as similar parameters are used. It is assumed that pump capacities for loading and unloading are similar, similar to the pipeline transport of the other energy carriers.

Table 90: Pump capacities for DME pipelines

Transport route	Pump capacity, kW	Discharge pressure, MPa
Rotterdam - Amsterdam	43752	10
Amsterdam - Delfzijl	125	10
Rotterdam - Zeeland	42883	10
Rotterdam - Nijmegen	30349	10
Nijmegen - Chemelot	28180	10
Nijmegen - Emmen	2168	10

Energy is only consumed by the pumps during the loading and unloading of DME onto and from the pipelines which is estimated to be 7078 MWh/day along all the transport routes.

7.5.5 Road transport

DME can be transported by T10-type tank containers which is used to transport ammonia. This is assumed to be the case as previously discussed, DME can be transported using the infrastructure that transports ammonia (Anon, 2011). The tank containers have a maximum weight of 20 tons and hydraulic capacity of 16415.2 litres (Botero, 2018). The tank containers have a transport pressure of 10 bar, at which DME is in a liquid state with a density of 670 kg/m^3 (Ihmels & Lemmon, 2007). Taking into account the weight of the trailer and the cabin which is estimated to be 5 tons and 4 tons respectively, 11 tons of DME can be transported by the T10-type tank container (Botero, 2018). At 11 tons, DME has a volume of 16416 litres while the hydraulic capacity of the tank containers is 16415.2 litres. Therefore, 11 tons of DME can be transported by the tank containers. Loading and unloading of the trucks are done using pumps which is assumed to take one hour each for loading and unloading at the source and destination. The system boundaries for road transport is similar to pipeline transport, with the only difference being the transport mode. This is shown in figure 21

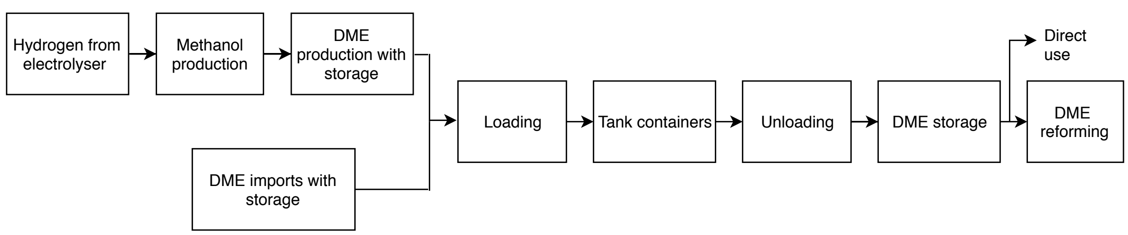

Figure 21: System boundaries for DME road transport

To model the transportation of DME by road, the number of tank containers needed for each route was first estimated. The parameters used to estimate the number of tank containers needed for each route is shown in table 91 followed by the estimated number of tank containers which is shown in table 92.

Table 91: Parameters used to estimate the number of tank containers needed for DME road transport (Yang & Ogden, 2007)(Wulf & Zapp, 2018)

Parameter	Value	Unit
Truck speed (average)	50	km/h
Fuel consumption	32	l/100km
Unloading and loading time	2	hrs

Table 92: Estimated number of tank containers needed

Route	Amount of DME, tons/day	Distance, km	Time taken, hrs	No. of trips per day	No. of tank containers needed
Rotterdam - Delfzijl	40	281	7.62	1	4
Rotterdam - Emmen	696	223	6.46	1	64
Rotterdam - Amsterdam	14008	75	3.5	3	425
Rotterdam - Zeeland	13770	83	3.66	3	418
Rotterdam - Chemelot	9049	179	5.58	2	412

Pumps are used to load and unload DME onto the T-10 type tank containers. Table 94 shows the pump capacity required for DME road transport which was designed using equation 15. The parameters used to design the pumps are listed in table 93. Pump capacities for loading is assumed to be similar for unloading while the number of pumps required is assumed to be equal to the number of tank containers needed for each route.

Table 93: DME pump design data (Ihmels & Lemmon, 2007)(Irvine, 2016)(Sashi Menon, 2005)

Parameter	Value	Unit
Molecular mass	0.046	kg/mol
Gas gravity	0.724	
Density of DME	670	kg/m^3

Table 94: Pump capacity for DME road transport

Vehicle type	Pump capacity, kW	Discharge pressure, MPa
T-10 Tank containers	130	0.1

The energy consumed by road transportation of DME includes loading of the DME, transportation and unloading of the DME at the destination. This is shown in table 95.

Table 95: Estimated energy consumption of DME road transport

Route	**Fuel consumption litres/day**	**Energy consumption of tube trailers, MWh/day**	**Loading and unloading, MWh/day**
Rotterdam - Emmen	719	7	25
Rotterdam - Amsterdam	9134	89	399
Rotterdam - Amsterdam	61200	594	2652
Rotterdam - Zeeland	66612	646	2608
Rotterdam - Chemelot	94397	916	2571
Total		2251	8256

Similar to methanol and ammonia, the pumps consume more energy than the tube trailers making it the dominant energy user in liquid road transport.

7.5.6 Energy efficiency of DME transport

Similar to energy efficiency of hydrogen transport, energy efficiency of DME transport is calculated using formula 16. The energy efficiencies of the DME transport systems are listed in table 96.

Table 96: Energy efficiency of DME transport systems

Transport medium	**Production, MWh/day**	**Storage, MWh/day**	**Transport medium, MWh/day**	**Reforming, MWh/day**	**Import, MWh/day**	**Total, MWh/day**	**Efficiency**
Pipeline	303162	1449	7078	4896	1880759	2197344	26%
Road	303162	1449	10507	4896	1880759	2200773	26%

Similar to all the energy carriers, pipeline transport is more energy efficient compared to road transport of DME when comparing the energy consumed by the transport mediums. As a whole, the system efficiencies are equal as the energy spent for the transport mediums are negligible compared to the energy spent for production and imports. Energy used for storage and reforming are also negligible compared to production and imports.

7.6 Synthetic methane transport

Synthetic methane is another energy carrier that was shortlisted and will be researched into, in this thesis. Synthetic methane is nothing but methane produced in a renewable manner and not from fossil fuels. The high content of methane in natural gas, gives synthetic methane similar properties to that of natural gas (Dobrota et al., 2013). The vast usage of natural gas for energy, and the bulk transportation across countries and continents gives synthetic methane the advantage of using existing knowledge that has been gained over the past few decades. The process of producing synthetic methane is called methanation, which is based on the Sabatier reaction involving hydrogen and CO_2 as raw materials (Guilera, Ramon Morante, & Andreu, 2018). The production of hydrogen has already been discussed in section 7.2.1 while CO_2 capture using DAC systems have been discussed in section 7.4. Guilera et.al, reports that the methanation process is carried out at a temperature of 300 - 400°C at a pressure which can vary from 4 to 20 bar, in the presence of a catalyst (Guilera et al., 2018). On the other hand, Parigi et.al, reports that the reaction can take place at a pressure varying from 1 - 100 bar at a temperature range varying from 200 - 600°C (Parigi, Giglio, Soto, & Santarelli, 2019). The methanation reaction is shown in the equation below.

$$CO_2 + 4H_2 \rightleftharpoons CH_4 + 2H_2O \tag{21}$$

Using the equation above, 1 kg of synthetic methane would require 0.5 kg of hydrogen. The paper from Guilera et.al, has a narrow range in terms of parameters that affect the reaction producing synthetic methane, and thereby this was used as the reference paper to model the synthetic methane production plants (Guilera et al., 2018). Guilera et.al, evaluates a 3470 ton/yr synthetic methane plant that has an electricity demand of 38 GWh/yr and 28 kW of heat is required (Guilera et al., 2018). The paper further states, that less heat is required as the production process is highly exothermic and thereby generates enough heat to be reused within the system (Guilera et al., 2018). Similar to the production of methanol, hydrogen is assumed to be combusted to generate the heat necessary, with an efficiency of 60% similar to natural gas. Therefore, to produce 1 kg of synthetic methane, 0.51 kg of hydrogen would be required. This is based on the fact that hydrogen has a calorific value of 141 MJ/kg. Table 97 lists the parameters used to model the synthetic methane production plant followed by table 98, which shows the amount of synthetic methane that can be produced in the Netherlands.

Table 97: Parameters used for modelling Synthetic methane production plants (Guilera et al., 2018)

Parameter	**Value**	**Unit**
Capacity	3470	kton/yr
Heat needed	28	kW
Electricity needed	38	GWh/yr
Process efficiency	80	%
Operating capacity	80	%

Table 98: Synthetic methane production in the Netherlands

Industrial cluster	**Hydrogen production, tons/day**	**Synthetic methane production, tons/day**	**Electricity demand, MWh/day**	**Heat demand, MWh/day**
Rotterdam	1785	2262	24996	157
Amsterdam	1648	2089	23082	145
Delfzijl	571	724	7994	50
Zeeland	603	765	8444	53
Total		5840		

A total of 5840 tons of synthetic methane can be produced in the Netherlands on a daily basis while a total of 6297 tons of hydrogen is combusted per year. This has to be compensated through increased imports.

7.6.1 Synthetic methane reforming

To estimate the mismatch in the supply and demand of synthetic methane in each industrial cluster, the demand for synthetic methane has to be estimated for each industrial cluster, based on the demand for hydrogen. Currently, steam reforming of methane is the widely accepted process for producing hydrogen, since it is more energy efficient compared to the other processes of partial oxidation and CO_2 reforming of methane (Mondal & Ramesh Chandran, 2014). Since commercial steam methane reformers are based on natural gas as the reaction input instead of pure methane, an additional step of desulfurization is introduced in the steam reforming process (Mondal & Ramesh Chandran, 2014). After the desulfurization process, methane is heated up to 550°C in a pre-reformer, a fixed bed reactor, to produce hydrogen and carbon-oxides (Mondal & Ramesh Chandran, 2014). The products are further heated to 600 - 700°C in a reformer to produce CO_2 and hydrogen (Mondal & Ramesh Chandran, 2014). A pressure swing absorption unit is then employed to obtain pure hydrogen (Mondal & Ramesh Chandran, 2014). Steam reforming of methane has a process efficiency of 85% (Mondal & Ramesh Chandran, 2014). Using this efficiency, the demand for synthetic methane can be estimated at each industrial cluster which is shown in table 99 .

Table 99: Synthetic methane demand in the Netherlands

Industrial cluster	**Hydrogen demand, tons/day**	**Synthetic methane demand, tons/day**
Rotterdam	3095	7228
Amsterdam	2197	5132
Delfzijl	128	299
Zeeland	1941	4533
Chemelot	1190	2780
Emmen	91	214
Total		20186

With the estimated supply and demand for synthetic methane known, 14348 tons of synthetic methane has to be imported on a daily basis. The quantity of synthetic methane that has to be transported across the six industrial clusters in the Netherlands is shown in table 100.

Table 100: Synthetic methane transported along each route in the Netherlands

Transport routes	**Amount of methanol, tons/day**
Delfzijl - Emmen	424
Delfzijl - Amsterdam	210
Rotterdam - Amsterdam	2833
Rotterdam - Zeeland	3769
Rotterdam - Chemelot	2780

The transport routes are similar to that of hydrogen as there is an excess in both Rotterdam and Delfzijl. Therefore, it was decided to distribute synthetic methane among the industrial clusters, similarly to that for hydrogen transport.

Steam reforming of synthetic methane is modelled after the steam reforming of methane, which requires both heat and electricity to power the process. As discussed before, hydrogen can be combusted to provide the heat source needed for the process. Table 101 shows the parameters used to model the synthetic methane reformers. The synthetic methane reformers have been based on a 197 ton/day commercial steam methane reformer analysed by Mondal et.al, (Mondal & Ramesh Chandran, 2014). It has to be noted that the commercial reformers include desulfurisation which is not required for synthetic methane reformers (Mondal & Ramesh Chandran, 2014). Since specific heat and electricity consumption values for the desulfurisation unit could not be realised, the electricity and heat demand estimated in this thesis includes the demand for the desulfurisation unit as well.

Table 101: Parameters used for modelling synthetic methane steam reforming plants (Mondal & Ramesh Chandran, 2014)(van Wijk, 2018)

Parameter	Value	Unit
Process efficiency	85	%
Electricity required	869	kWh/tonCH_4
Heat required	2538	kWh/tonCH_4
Hydrogen combustion efficiency	60	%
Hydrogen energy density	141	MJ/kg
Scaling factor	0.65	

As previously discussed, only 96 PJ of hydrogen is required for non-energy uses and thereby only that much of hydrogen has to be produced by the synthetic methane reformers. Using the parameters listed, table 102 shows the synthetic methane reformer plant capacities at each industrial cluster alongside the electricity and heat demands.

Table 102: Synthetic methane reformers at the six industrial clusters

Industrial cluster	**Synthetic methane reformer capacity, tons/day**	**Electricity demand, MWh/day**	**Heat demand, MWh/day**	**Hydrogen combusted, tons/day**
Rotterdam	1563	581	1698	72
Amsterdam	1110	413	1206	51
Delfzijl	65	24	70	3
Zeeland	980	365	1065	45
Chemelot	601	224	653	28
Emmen	46	17	50	2

An estimated 202 tons of hydrogen is lost on a daily basis during the process of the steam reforming of synthetic methane.

7.6.2 Synthetic methane storage

Methane or natural gas is usually stored: 1) In bulk as a liquid in LNG tanks, 2) In small quantities in compressed tanks like tube trailers and 3) Balanced in pipelines. Since the scale of storage of synthetic methane has to be on a large-scale, the 2nd and 3rd option is not suitable (Pasini et al., 2019)(Tractebel Engineering, 2015). The first option involves liquefying synthetic methane just for the purpose of storage, which then has to be regasified, if it has to be transported by pipeline or compressed road transport. Therefore liquefying methane would not be beneficial as it just consumes extra energy and increases the costs further. Biomethane which is a gaseous product of biomass is usually stored in large low-pressure storage tanks at pressures as low as 2 - 8 psi, close to atmospheric pressure (Krich et al., 2005). This form of storage is more suitable to store gaseous synthetic methane at a large-scale, as it does not require additional energy for storage. Thereby, it is assumed that synthetic methane will be stored in low pressure storage tanks that store biomethane. Table 103 shows the storage tank capacities needed at the source and destination. It has to be noted that gaseous synthetic methane has a density of 0.656 kg/m^3 at atmospheric conditions, requiring high volume storage. This may increase the costs and space required for storage tanks.

Table 103: Synthetic methane storage capacity

Industrial cluster	Storage capacity at the source, tons/day	Storage capacity at the port, tons/day	Storage capacity at destination, tons/day
Rotterdam	2622	121651	-
Amsterdam	2089	-	2834
Delfzijl	724	-	-
Zeeland	765	-	3770
Chemelot	-	-	2780
Emmen	-	-	635

7.6.3 Maritime shipping

Natural gas is transported as a liquid by LNG tankers across countries, therefore it is assumed that synthetic methane would be transported as a liquid by LNG tankers as well (Dobrota et al., 2013). Since synthetic methane and natural gas are very similar, it is assumed that there will be no need for any modifications to the LNG tankers (Dobrota et al., 2013). LNG tankers have been discussed in detail in section 7.2.5. As seen in figure 22, the system boundaries involved in the maritime shipping of synthetic methane includes the synthetic methane sold at the port of source, shipping, and either regasification or storage at the port of Rotterdam. Regasification or storage at the port of Rotterdam will depend on the transport mode used on land.

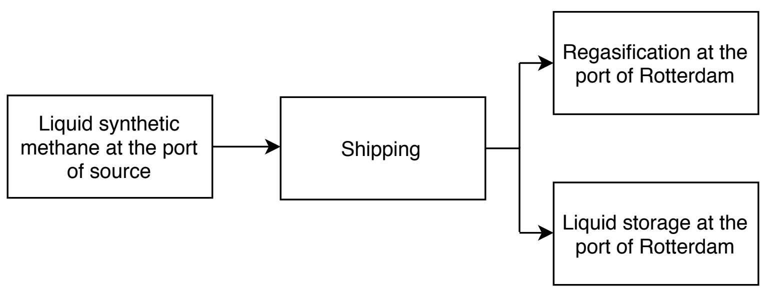

Figure 22: System boundaries for synthetic methane shipping

The ship that has been modelled in this thesis to transport synthetic methane, has a capacity of 150000m^3. Table 104 shows the parameters used for modelling maritime shipping of synthetic methane. With a density of 422 kg/m^3 for liquid synthetic methane, 63354 tons can be transported per trip using this tanker. Assuming that a heel of 4% is kept in the tanks after unloading the liquid synthetic methane, the net tonnage of comes down to 60100 tons per trip.

Table 104: Parameters used for synthetic methane shipping (Dobrota et al., 2013)(Polemis, 2013)(Rodrigue et al., 2017)(Rogers, 2018)

Parameter	Value	Unit
Capacity of ship	150000	m^3
Speed	19 (35)	knots (km/h)
Distance	8000	km
Boil of losses	0.12	% per day
Heel	4	% of total capacity
Fuel consumption	48	tons/day
Time at port (source and destination)	3	days

14348 tons of synthetic methane has to be imported on daily basis to satisfy the hydrogen demand in the Netherlands. The LNG tanker can transport 60100 tons of synthetic methane in one trip, therefore one trip every four days would be enough to satisfy the daily demand in the Netherlands. The energy consumption for maritime shipping takes into account the energy used for synthetic methane production, liquefaction at the port of source, fuel consumption of the ship, and regasification with liquid storage or only liquid storage at the port of destination. The parameters used to estimate the energy consumed for synthetic methane maritime shipping is shown in table 105. Table 106 shows two scenarios; 1) Regasification is needed, since further transport on land will be through compressed synthetic methane road transport or pipeline transport and 2) Liquid storage only would be needed, since synthetic methane will be transported further as a liquid by road.

Table 105: Parameters used to estimate the energy consumed for synthetic methane shipping (Guilera et al., 2018)(Songhurst, 2018)(Engineering Toolbox, 2003)

Parameter	Value	Unit
Energy required for synthetic methane production	45	$kWh/kgCH_4$
Energy required for synthetic methane liquefaction	890	$kWh/tonCH_4$
Energy content of liquid synthetic methane	50	$MJ/kgCH_4$
Energy density of HFO	39000	MJ/tons

For LNG regasification, the energy required for this process is estimated to be 1.5% of the energy content of the liquid (Bruno et al., 2017). The process description of regasification has been elaborated in section 7.2.5. Specific energy consumption of liquid synthetic methane storage could not be realised, therefore it was assumed that energy consumed by liquid hydrogen storage and liquid synthetic methane storage to be the same. Bartel et.al, estimates this to be 1.82 kWh/kg of liquid hydrogen (Bartels, 2008). In reality, energy consumption of liquid synthetic methane storage is expected to be lower as liquid hydrogen is stored at -253 °C while liquid synthetic methane is stored at -163 °C.

Table 106: Estimated energy consumption of synthetic methane shipping

Sceanrio	Production and liquefaction, MWh/day	Fuel consumption, MWh/day	Regasification, MWh/day	Liquid storage, MWh/day	Total, MWh/day
Compressed synthetic methane transport	729434	1635	12521	6582	750171
Liquid synthetic methane transport	729434	1635	-	6582	737651

The estimated energy consumption for gaseous synthetic methane at the port of Rotterdam is 750171 MWh/day, which is higher than the estimated energy consumption for liquid synthetic methane, which is 737651 MWh/day. This is a result of the additional energy consumed for regasification of liquid synthetic methane at the port of Rotterdam for gaseous synthetic methane. Despite this, in both scenarios, the energy consumed by the production of synthetic methane dominates the energy consumption of the system.

7.6.4 Pipeline transport

Natural gas is one of the largest traded commodity, with natural gas pipelines present in several countries (Medleva, 2019). Currently more than 3 million miles of natural gas pipelines transporting 25 trillion cubic feet is present in the United States alone (EIA, 2018). Natural gas pipeline transport has been the most economical form of transporting natural gas over long distances in large quantities (Sashi Menon, 2005). Synthetic methane is expected to be transported by natural gas pipelines, as natural gas constitutes of approximately 95% methane. Figure 23 shows in detail the system components involved in the transport of synthetic methane by pipeline. As seen in figure 23, the system boundaries for transporting synthetic methane by pipelines includes: hydrogen production, synthetic methane production with storage, synthetic methane import with regasification at the port of Rotterdam, compression and decompression, synthetic methane reforming with storage at the destination and the transport medium - pipeline.

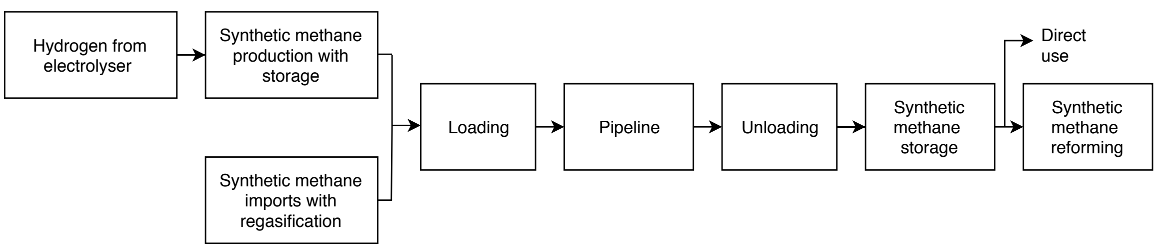

Figure 23: System boundaries for synthetic methane pipelines

The procedure for designing pipelines in section 7.1 was based on the design for natural gas pipelines. Thereby designing synthetic methane pipelines follow the same procedure and do not require any modification. Since synthetic methane is a gas, the velocity in the pipeline is restricted to 60 m/s as per NORSOK standards mentioned in section 7.1. Table 107 shows the parameters used to design synthetic methane pipelines.

Table 107: Synthetic methane pipeline design data (Sashi Menon, 2005)(Knoppe, 2015)(Engineering Toolbox, n.d.)

Parameter	**Value**	**Unit**
Average pressure in the pipeline	3.5	MPa
Design factor	0.5	
Roughness factor	0.00002	m
Base pressure of the pipeline	0.101	MPa
Base temperature of the pipeline	288	K
Density of steel	7900	kg/m3
Corrosion allowance	0.001	m
Average compressibility factor	0.9	
Molecular mass	0.016	kg/mol
Gas gravity	0.5537	
Average temperature	288	K
Density of methane	24.6	kg/m3
Specific heat	1.31	
Viscosity	0.000102	P

The pipelines were designed using the design procedure mentioned in figure 5 taking into account the data in table 107. Table 108 lists the results of the pipeline designs including the dimensions and costs for utilising different steel grades. The x52 steel grade was the most economical along the Delfzijl - Emmen and Delfzijl - Amsterdam routes while the x65 steel grade was more economical along the other routes. The average pressure used in the pipeline was chosen to be 3.5 MPa, similar to hydrogen pipeline transport which is in line with the distribution network transport pressure of 4 MPa for natural gas pipelines in the Netherlands (Gasunie, 2004). Similar to hydrogen, the low density and low viscosity of synthetic methane had an effect on the velocity of synthetic methane flowing through the pipeline. To make sure, the velocity was within the NORSOK standards of 60 m/s, either the pressure had to be reduced or the pipeline diameter had to be increased.

Table 108: Synthetic methane pipeline design

Route	Amount, tons/day	Distance, km	Steel grade	Thickness, m	Outer diameter, m	NPS, inch	Cost of pipeline, M€
Delfzijl - Emmen	424	60.7	x42	0.0019	0.0731	2.5	0.22
			x52	0.0017	0.0731	2.5	0.20
			x65	0.0015	0.073	2.5	0.21
			x70	0.0015	0.073	2.5	0.22
Delfzijl - Amsterdam	210	176	x42	0.0019	0.0731	2.5	0.64
			x52	0.0017	0.0731	2.5	0.59
			x65	0.0015	0.073	2.5	0.61
			x70	0.0015	0.073	2.5	0.65
Rotterdam - Amsterdam	2833	59.6	x42	0.003	0.1683	6	0.81
			x52	0.0025	0.1682	6	0.70
			x65	0.0022	0.1683	6	0.69
			x70	0.0021	0.1683	6	0.73
Rotterdam - Zeeland	3769	63.3	x42	0.0033	0.1937	7	1.09
			x52	0.0028	0.1937	7	0.94
			x65	0.0024	0.1938	7	0.92
			x70	0.0023	0.1938	7	0.96
Rotterdam - Chemelot							
Rotterdam - Nijmegen	2780	81.1	x42	0.003	0.1683	6	1.10
			x52	0.0025	0.1682	6	0.96
			x65	0.0022	0.1683	6	0.94
			x70	0.0021	0.1683	6	0.99
Nijmegen - Chemelot	2780	90.5	x42	0.003	0.1683	6	1.23
			x52	0.0025	0.1682	6	1.07
			x65	0.0022	0.1683	6	1.05
			x70	0.0021	0.1683	6	1.10

To compress the gas to the respective transport pressure, compressors are required. Equation 14 was used to design and estimate the compressor sizes needed for the pipeline transport of synthetic methane which is shown in table 109. The suction pressure for the compressor was 0.1 MPa, which is the storage pressure of synthetic methane. The parameters used for modelling the compressors have been listed in the bottom half of table 107, as similar parameters are used. Another assumption that is made in this thesis is that the decompressor at the end of the pipeline is assumed to be similar to the compressor at the beginning of the pipeline and thereby the compressor capacities are the same.

Table 109: Compressor capacities required for synthetic methane pipelines

Transport route	**Compressor size, kW**	**Discharge pressure, MPa**
Delfzijl - Emmen	7134	3.5
Delfzijl - Amsterdam	3535	3.5
Rotterdam - Amsterdam	47677	3.5
Rotterdam - Zeeland	63422	3.5
Rotterdam - Nijmegen	46775	3.5
Nijmegen - Chemelot	10167	3.5

Like the other energy carriers, energy is only consumed by the compressors during loading and unloading of synthetic methane onto and from the pipeline. This is estimated to be 8578 MWh/day.

7.6.5 Compressed road transport

Synthetic methane can be transported by road in its compressed form by steel tube trailers with a maximum payload of 45 tons at a pressure of 250 bar (Botero, 2018). The net payload of the tube trailers is 19 tons after subtracting the weight of the semi trailer and the cabin which weighs 20 tons and 6 tons respectively (Botero, 2018). Eventhough 19 tons of payload can be transport, the tube trailer only has a hydraulic capacity of 24640 litres. At a pressure of 250 bar, synthetic methane has a density of 182 kg/m^3, which only permits 4.5 tons of synthetic methane to be transported using the tube trailer. Loading and unloading of the tube trailers are done using compressors which is assumed to take one hour each for loading and unloading at the source and destination (Botero, 2018). The system components involved in the transport of compressed synthetic methane by road can be seen in figure 24. The system components are similar to that of pipeline transport except for the transport medium - tube trailers.

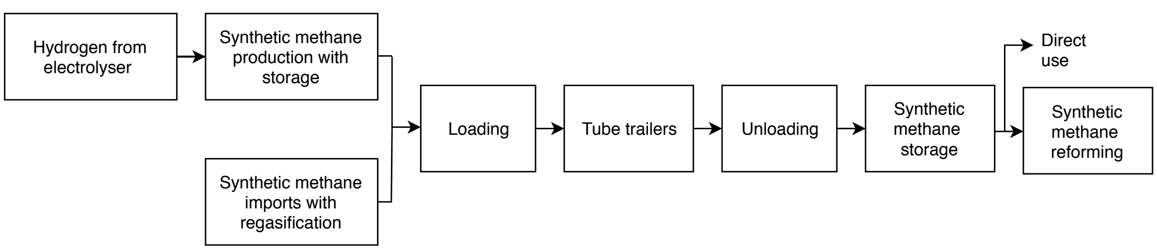

Figure 24: System boundaries for compressed synthetic methane road transport

To model the transport of synthetic methane transport, the number of tube trailers required along each route was estimated. The parameters used to estimate the number of tube trailers needed for each route is shown in table 110 followed by the number of tube trailers estimated for each route, which is shown in table 111.

Table 110: Compressed synthetic methane road transport technical parameters (Yang & Ogden, 2007)(Botero, 2018)(Wulf & Zapp, 2018)

Parameter	**Value**	**Unit**
Truck speed (average)	50	km/h
Fuel consumption	32	l/100km
Unloading and loading time	2	hrs

Table 111: Number of tube trailers and trips needed for compressed synthetic methane road transport

Road routes	Amount, tons/day	Distance, km	Time taken per trip, hrs	No. of trips required	Tube trailers needed
Delfzijl - Emmen	424	76	3.52	3	32
Delfzijl - Amsterdam	210	222	6.44	1	47
Rotterdam - Amsterdam	2833	75	3.5	3	211
Rotterdam - Zeeland	3769	83	3.66	3	281
Rotterdam - Chemelot	2780	179	5.58	2	310

Similar to pipeline transport, compressors are required to compress and load synthetic methane at 250 bar onto the tube trailer. Table 113 shows the compressor capacity required for compressed road transport which was designed using equation 14. The parameters used for modelling the compressor has been listed in table 112. It is also assumed that the decompressors at the destination to unload the synthetic methane is similar to the compressors and thereby the compressor capacities are similar. The number of compressors required for each route is assumed to be equal to the number of tube trailers required for each route. This assumption is based on the fact that all the tube trailers are expected to be loaded at the same time and thereby the compressors cannot be shared.

Table 112: Synthetic methane compressor design parameters for road transport (Sashi Menon, 2005)(Engineering Toolbox, n.d.)

Parameter	Value	Unit
Average compressibility factor	0.9	
Molecular mass	0.0016	kg/mol
Gas gravity	0.5537	
Average temperature	288	K
Density of synthetic methane	182	kg/m3
Specific heat	1.31	
Viscosity	0.000102	P

Table 113: Compressor capacity for synthetic methane road transport

Vehicle type	Compressor size, kW	Discharge pressure, MPa
Steel tube trailers	5741	25

The energy consumed by the compressed road transport includes the fuel consumption of the tube trailer and the energy consumed during loading and unloading. This is shown in table 114.

Table 114: Estimated energy consumption of synthetic methane compressed road transport

Route	**Fuel consumption litres/day**	**Energy consumption of tube trailers, MWh/day**	**Loading and unloading, MWh/day**
Delfzijl - Emmen	4669	45	8818
Delfzijl - Amsterdam	6708	65	12952
Rotterdam - Amsterdam	30384	295	58145
Rotterdam - Zeeland	44780	434	77435
Rotterdam - Chemelot	71027	689	85426
Total		1528	242775

The energy consumed for loading and unloading is very high in comparison to the fuel used for the tube trailers. This could be due to the fact that synthetic methane is stored at atmospheric pressure, increasing the compression ratio required and thereby increasing the compression capacity and energy consumed.

7.6.6 Liquid road transport

Synthetic methane can also be transported as a liquid by road, in specially built LNG road tankers (P.E & Fernandez, 2013). The road tankers have a capacity of 10500 gallons which would translate to 4.3 tonnes of liquid synthetic methane (P.E & Fernandez, 2013). This is estimated by taking into account that liquid synthetic methane has a density of 422 kg/m^3. The time taken to load and unload liquid synthetic methane is approximately four hours each (P.E & Fernandez, 2013), which is relatively long compared to compressed synthetic methane tube trailers. The system components involved in the transport of liquid synthetic methane by road can be seen in figure 25. The system components vary with respect to compressed road transport, as liquefaction and regasification of synthetic methane is required at the source and destination, respectively. Another difference, is that synthetic methane imports do not have to be regasified instead liquid synthetic methane storage will only be required at the port of Rotterdam. Regasification of the liquid synthetic methane also includes storage for liquid synthetic methane.

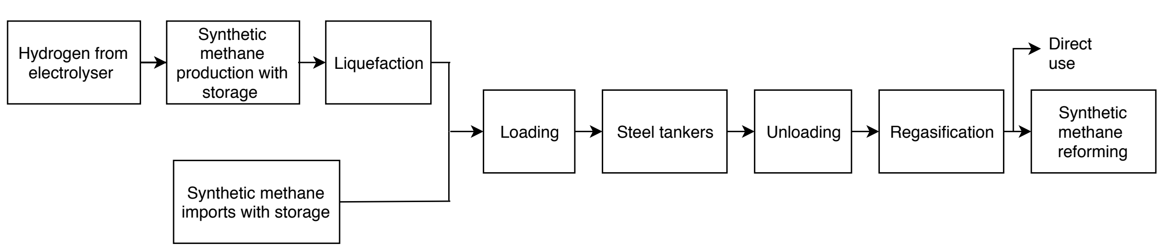

Figure 25: System boundaries for liquid synthetic methane road transport

Following the similar trend in literature, specially built LNG road tankers are used for transporting liquid synthetic methane in this thesis. The technical parameters to model liquid synthetic methane road transport remain the same as compressed synthetic methane road transport except for the loading and unloading time for liquid synthetic methane road transport is four hours each, at the source and destination (P.E & Fernandez, 2013). Table 115 shows the number of tankers and trips needed for each route on a daily basis, to satisfy the demand.

Table 115: Number of trips and tankers needed for each route

Road routes	Amount of synthetic methane, tons/day	Distance, km	Time taken per trip, hrs	No. of trips required	Tankers needed
Delfzijl - Emmen	424	76	9.5	1	26
Delfzijl - Amsterdam	210	222	12.4	1	13
Rotterdam - Amsterdam	2833	75	9.5	1	169
Rotterdam - Zeeland	3769	83	9.7	1	225
Rotterdam - Chemelot	2780	179	11.6	1	166

Loading and unloading liquid synthetic methane onto the tankers requires pumps. Table 117 shows the pump capacity required, which was designed using equation 15. The parameters used to model the pumps are listed in table 116. Similar to compressed hydrogen road transport, the pump capacity for loading is assumed to be similar to unloading and the number of pumps used is equal to the number of road tankers required for each route.

Table 116: Liquid synthetic methane pump design data (Weber et al., 2013)(Sashi Menon, 2005)

Parameter	Value	Unit
Molecular mass	0.016	kg/mol
Gas gravity	0.5537	
Density of liquid synthetic methane	422	kg/m^3

Table 117: Pump capacity for liquid synthetic methane road transport

Vehicle type	Pump capacity, kW	Discharge pressure, MPa
LNG road tankers	65	0.1

To liquefy synthetic methane, synthetic methane has to be cooled down to cryogenic temperatures of -163 °C. Liquefaction plants used for methane will slightly differ from the liquefaction of natural gas as no pre-treatment of the gas is required unlike natural gas, which requires dehydration and mercury removal. Liquefaction of methane will take place at -163°C, using various refrigerants depending on the proprietary technology used (Han & Lim, 2012). The liquefaction process usually takes place in three steps: pre-cooling, liquefaction and sub-cooling, each step at different pressures to bring synthetic methane to cryogenic temperatures (Han & Lim, 2012). The liquefaction plant modelled here will be based on the Sabine pass liquefaction plant in the United States which has a capacity of 61644 tons/day (Songhurst, 2018). The parameters required to model the liquefaction plant is listed in table 118 followed by table 119, which shows the liquefaction plant capacities needed at Delfzijl and Rotterdam and the energy required for each plant.

Table 118: Parameters used for modelling synthetic methane liquefaction plants (Songhurst, 2018)

Parameter	Value	Unit
Electricity needed (61644 tons/day)	19791	GWh/yr
Operating capacity	80	%
Density of liquid synthetic methane	422	kg/m3

Table 119: Synthetic methane liquefaction plant capacities

Industrial cluster	Liquefaction plant size, ton/day	Liquid hydrogen output, ton/day	Energy consumption, MWh/day
Delfzijl	793	634	698
Rotterdam	11729	9383	10317

The liquefaction plant is expected to operate at 80% of its total capacity, as to mimic a practical scenario where operational capacity is not at 100% and necessary maintenance stops reduce total output. The capacity at Rotterdam is lower than what would have been needed due to liquid synthetic methane coming via ship to the port of Rotterdam, which can be loaded directly onto the road tankers after being stored at the port. This eliminates the need for a higher liquefaction capacity at Rotterdam. At the destination, liquid synthetic methane will be unloaded from the road tankers into a liquid storage. For liquid synthetic methane to be used further, the hydrogen has to be regasified. Table 120 shows the regasification capacities required at each destination and the energy consumption for each. Similar to the maritime transport of synthetic methane, the regasification plants have been modelled after the GATE LNG terminal at Rotterdam which has a capacity of 54000m^3. The energy required for regasification and storage is estimated based on the data in table 105.

Table 120: Synthetic methane regasification plant capacity and energy requirements at the destination

Industrial cluster	Regasification plant capacity, ton/ day	Energy consumption, (Regasification) MWh/day	Energy consumption, (storage) MWh/day
Emmen	424	88	7727
Amsterdam	3044	634	5539
Zeeland	3769	590	5157
Chemelot	2780	785	6860

The energy consumed by liquid synthetic methane road transport includes liquefaction, loading, transport, unloading and regasification. The fuel consumption for transporting liquid synthetic methane by the tankers is first estimated, which is shown in table 121. This is followed by the final energy consumption estimated, which is shown in table 122.

Table 121: Fuel consumption of the road tankers used for liquid synthetic road transport

Route	Fuel consumption litres	Energy consumption, MWh/day
Delfzijl - Emmen	1265	12
Delfzijl - Amsterdam	1847	18
Rotterdam - Amsterdam	8112	79
Rotterdam - Zeeland	11952	116
Rotterdam - Chemelot	19017	184
Total	42193	409

Table 122: Energy consumption of liquid synthetic methane road transport

Road tanker MWh/day	Loading and unloading, MWh/day	Liquefaction, MWh/day	Regasfication, MWh/day	Storage, MWh/day	Total, MWh/day
409	934	11014	2097	18327	32783

The energy consumed by the storage and the liquefaction of synthetic methane dominate the total energy consumption. It has to be noted that the energy consumption of liquid synthetic methane storage was based on that of liquid hydrogen and thereby is over estimated.

7.6.7 Energy efficiency of synthetic methane transport

Energy efficiency of synthetic methane transport is calculated using formula 16 and listed in table 123.

Table 123: Energy efficiency of synthetic methane transport systems

Transport medium	Production, MWh/day	Storage, MWh/day	Transport medium, MWh/day	Reforming, MWh/day	Import, MWh/day	Total, MWh/day	Efficiency
Pipeline	339961	-	8578	6367	750171	1105078	28%
Compressed road	339961	-	244303	6367	750171	1340803	23%
Liquid road	339961	-	33718	6367	737651	1117697	28%

The energy efficiencies of pipeline and liquid road transport are almost the same but compressed road transport has a lower efficiency by 5%. This could be attributed to the fact that many compressors of very high capacities, that are needed for loading and unloading at 250 bar, consumes a large amount of electricity. This is the case for compressed hydrogen transport as well, where compressed hydrogen road transport has a lower efficiency compared to other transport modes.

8 System Costs

This chapter will first discuss how the system costs are calculated and what parameters are considered in the calculation of the system costs. This is followed by the detailed calculation of the system costs for each energy carrier within each transport mode.

8.1 System costs calculation

To compare the costs of transporting each energy carrier, it was decided to calculate the costs relative to the energy density of the energy carrier. Estimating costs in this way will provide a fair comparison amongst the energy carriers based on not just the hydrogen carrying capability but also the energy production capability when utilised directly at the destination. The system costs encompass the individual costs of the components within the system boundaries resulting in a final estimated cost for a whole system.

The calculation involves estimating the capital expenditure known as the CAPEX and the operating expenditure known as the OPEX for each system component. CAPEX includes the cost of the equipments along with the direct costs, indirect costs and the working capital associated with the cost of the equipments. The direct costs includes the installation of the equipment, electrical, piping, instrumentation and other service facilities installation associated to the equipment. The indirect costs covers the EPC (Engineering, procurement and construction) costs and other administrative costs. Wherever the costs of these could not be found, factors were used as a percentage of the equipment costs as could be found in Peter et al, and WillbrosEngineeringInc (Peter & Timmerhaus, 2003)(Willbros Engineering Inc, 2005). For all cases, CAPEX is updated to 2018 costs using the Chemical Engineering Plant Cost Index (CEPCI). OPEX consists of the overhead expenditures of the plant, labour costs, administrative costs like tax and also maintenance costs of the plants. Realising the exact numbers for OPEX was quite difficult in most cases and thereby assumptions were made for OPEX based on the various literature from where the CAPEX of the equipments were taken from. As standard across the entirety of this thesis, a scaling factor of 0.65 was used unless explicitly mentioned by literature to use otherwise, and a conversion factor of 1 USD to 0.89 € was used to convert costs in dollars to euros. The parameters used for estimating the costs of each system component is listed in the respective sub-sections in this chapter.

Since, CAPEX is a one-time investment and OPEX is a yearly expenditure, it was necessary to annualise the CAPEX. The CAPEX is annualised using the formula below.

$$C_{ann} = CAPEX * (\frac{r}{1-(1+r)^{n}}) \tag{22}$$

where r is the discount rate in % and n is the lifetime of the equipment. The discount rate is taken as 5% while the lifetime varies depending on the equipment.

To calculate the costs in terms of the energy density of the carrier, the total cost for a component was divided by the product of the mass of the energy carrier and the energy density in MWh/kg, resulting in costs with a unit of €/MWh. The system costs are calculated as an addition of the costs incurred by the individual system components, in relation to the mass balance of the system.

8.2 Hydrogen transport

The first system component that was modelled for the transport of hydrogen or any of the energy carriers was the hydrogen electrolyser. The electrolyser technology used and the respective capacities have been previously discussed in detail and modelled in section 7.2.1. The parameters used for estimating the costs of the electrolysers are listed in table 124.

Table 124: Hydrogen electrolyser assumptions (Lensink & Pisca, 2019)(E4techSarl & ElementEnergy, 2014)

Parameter	**Value**	**Unit**
Capex	1100	€/kW
Opex	4	% of Capex
Operational capacity	80	%
Electricity	0.07	€/kWh
Interest rate	5	%
Lifetime	20	years
Stack costs	660	€/kW
Stack lifetime	10	years

The Capex of the PEM electrolysers was estimated to be 1100 €/kW with the Opex assumed to be 4% excluding electricity costs (E4techSarl & ElementEnergy, 2014). The Capex of the PEM electrolyser has been projected to vary between 900 and 1300 €/kW, with the central case estimated to be 1100 €/kW (E4techSarl & ElementEnergy, 2014). E4tech et.al, reports that the Opex is expected to decrease as the electrolysers scale up, while also mentioning that an optimistic Opex of 1.5 could be used for capacities higher than 1.5 MW (E4techSarl & ElementEnergy, 2014). Thomas estimates the Opex to be around 4 - 5 % but he further mentions that in the future the Opex will tend to 1 - 1.5% of the Capex by 2050 (Thomas, 2018). In this thesis, cost estimations are based on 2018 costs, therefore an Opex of 4% of the Capex is used. It is also assumed that the electrolyser will have a lifetime of 20 years but the stacks will only have a lifetime of 10 years. Thereby, the stacks would have to be replaced atleast once during the 20 year lifespan of the electrolyser.

As discussed in chapter 6, it also assumed that offshore wind farms would supply the electricity needed for the operation of the electrolyser. Therefore, the cost of electricity has to be the price of electricity sold by the offshore wind farm operators. Lensink et.al, made estimates for the price of electricity that would be sold by the offshore wind farms in the future based on current costs. Across the offshore wind farms that will be erected in the Dutch area of the North Sea, the price of electricity averages to 0.07 €/kWh (Lensink & Pisca, 2019). The selling prices vary across the wind farms according to the distance of the wind farm from the coast and the topography of the seabed, thereby the prices could be higher or lower than the estimated price of 0.07 €/kWh (Lensink & Pisca, 2019). Table 125 shows the Capex and Opex of operating the electrolysers.

Table 125: Hydrogen electrolyser costs

Industrial cluster	**No. of electrolysers**	**Capex, M€**	**Opex, M€**	**Electricity costs, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam	222	6105	244.2	2722.6	489.9	3931.1
Amsterdam	205	5637.5	225.5	2514.1	452.4	3630.0
Delfzijl	71	1952.5	78.1	870.7	156.7	1257.2
Zeeland	75	2062.5	82.5	919.8	165.5	1328.1

Therefore the cost of hydrogen production was estimated to be 153 €/MWh using the hydrogen higher heating value of 141 MJ/kg.

8.2.1 Hydrogen storage

As discussed in section 7.2.4, storage is required after hydrogen production, at the port of Rotterdam to store the imported hydrogen and also at the destination to store the unloaded hydrogen. Table 126 shows the parameters used to estimate the costs of hydrogen storage both in gaseous and liquid form.

Table 126: Parameters used for estimating the costs of storing hydrogen (Yang & Ogden, 2007)

Parameter	**Value**	**Unit**
Capex of gaseous storage	429.8	€/kgH_2
Opex of gaseous storage	5	% of Capex
Capex of liquid storage	32.2	€/kgH_2
Opex of liquid storage	9	% of Capex
Interest rate	5	%
Lifetime	20	years

Table 127 and 128 show the costs of storing gaseous and liquid hydrogen at the source while table 129 shows the costs of storing gaseous hydrogen at the destination. In the case of liquid transport, storage at the destination will be included with the regasification costs.

Table 127: Estimated costs of gaseous hydrogen storage

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam	1786	767.5	38.4	61.6	100.0
Amsterdam	1649	708.7	35.4	56.9	92.3
Delfzijl	571	245.4	12.3	19.7	32.0
Zeeland	604	259.6	13.0	20.8	33.8
€/MWh					4

Table 128: Liquid storage costs for shipping

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam	10074	324.7	26.1	29.2	553
€/MWh					1

Table 129: Estimated costs of hydrogen storage at the destination

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Emmen	92	39.5	2.0	3.2	5.1
Amsterdam	550	236.4	11.8	19.0	30.8
Zeeland	1338	575.0	28.8	46.1	74.9
Chemelot	1190	511.8	25.6	41.1	66.7
€/MWh					5

From the tables above, it can be observed that the costs of liquid and gaseous hydrogen storage varies with the latter being the more expensive of the two. This is attributed to the fact that liquid hydrogen has a higher density and thereby smaller storage tank volumes are required. Even though, the Opex of liquid hydrogen storage is relatively higher due to the cryogenic state that liquid hydrogen has to be stored in, this is compensated by the reduced volume needed for storage.

8.2.2 Maritime shipping

Hydrogen can be shipped in its liquid form as discussed in section 7.2.5, therefore hydrogen has to be bought in its cryogenic state from the port of source. At the port of Rotterdam, depending on how the hydrogen is transported on land, liquid hydrogen has to either be stored as a liquid for liquid road transport or regasified to transport gaseous hydrogen by pipeline or compressed road transport. This is depicted in the system boundaries for maritime shipping shown in section 7.2.5. Also discussed in the same section, the transport of liquid hydrogen by ship is modelled after LNG tankers and thereby the costs will follow suit. Ships in general are chartered [6] and not owned by companies that transport goods from source to destination. The charter rates vary according to the demand for the ships and thereby are volatile. Other costs associated with maritime shipping include insurance, maintenance, fuel, payments for manning the ship and port charges. Payments for manning the ship involves salaries for the captain and crew while port charges are the charges incurred when the ship is docked at the port of source to load and at the port of destination to unload goods. Table 130 shows the parameters used for estimating the costs of transporting hydrogen by ship followed by table 131 which shows the cost breakdown per trip for shipping hydrogen over a distance of 8000 km.

Table 130: Parameters used for estimating hydrogen shipping costs (Dobrota et al., 2013)(Polemis, 2013)(Rodrigue et al., 2017)(Rogers, 2018)

Parameter	**Value**	**Unit**
Charter rate	48950	€/day
Port charges	1500000	€/year
Manning charges	500000	€/year
Boil-off loses	0.12	%/day
Maintenance & repair	300000	€/year
Insurance	500000	€/year
Fuel consumption (HFO)	48	tons/day
Fuel costs	380	€/ton

Table 131: Hydrogen shipping cost breakdown

Parameter	**Costs, €/trip**
Charter rate	636350
Port charges	12329
Manning charges	17808
Maintenance & repair	10685
Insurance	17808
Fuel costs	227506
Total costs	922486

Since one ship has to be chartered every two days, 183 trips would be required annually to satisfy the yearly import demand. Therefore the total cost for shipping hydrogen over 8000 km for one year was estimated to be 168 M€, which translates to 2 €/MWh. This cost is still not the final cost, as the cost of liquid hydrogen sold at the port of source has to be included into the transport

[6] Chartering a ship refers to leasing the ship for a trip or a period of time

costs as well. From literature, various prices ranging from 3 - 6 $/kg$H_2$ could be found (Yang & Ogden, 2007)(Bartels, 2008)(Wulf & Zapp, 2018)(IEA, 2019). Since imports are expected to be sourced from countries with a low production cost for hydrogen but to also be on the conservative end of the estimate, a hydrogen price of 4 €/kgH_2 (103 €/MWh) was assumed. Hydrogen produced from the electrolysers are still in its gaseous state and has to be liquefied before being loaded onto the tanker. The Idealhy project commissioned by the European Union have estimated the cost of liquefying hydrogen (Stolzenburg & Mubbala, 2013). The parameters used to estimate the cost of hydrogen liquefaction plants are listed in table 132 .

Table 132: Parameters used for estimating hydrogen liquefaction costs (Stolzenburg & Mubbala, 2013)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Capex	32.2	€/kgliquidH_2
Opex	4	% of Capex
Operating capacity	75	%
Electricity costs	0.07	€/kWh
Interest rate	5	%
Lifetime	20	years

Using the parameters listed above, the cost of liquefying hydrogen was estimated, which is shown in table 133. The daily capacity of the liquefaction plant was assumed to be half of the total capacity of the ship as the ship is chartered every two days.

Table 133: Estimated hydrogen liquefaction costs

Plant size, ton/day	**Capex, M€**	**Output, ton/day**	**Electricity cost, M€**	**Opex, M€**	**Capex, M€/yr**	**Total costs, M€/yr**
7080	3166.3	5310	917.1	126.7	254.1	1297.8

The liquefaction costs for hydrogen was estimated to be 20 €/MWh, which added to the cost of hydrogen produced, results in a cost of 123 €/MWh. Therefore the cost of liquid hydrogen imports coming into the port of Rotterdam will be the cost of liquid hydrogen sold at the port of source and the shipping costs, which is estimated to be 125 €/MWh. This cost still does not account for the boil off losses which was estimated in section 7.2.5 to be 121 tons per trip resulting in 22 ktons lost per year. This brings the cost of shipping hydrogen to an estimated cost of 127 €/MWh.

At the port of Rotterdam, if the hydrogen is further on land in liquid form by steel road tankers, only the cost of liquid hydrogen storage tanks have to be included in the system costs. If the hydrogen has to be transported as compressed gas through pipeline or road, regasification costs have to be included in the system costs. Regasification plants include liquid hydrogen storage as well. Table 134 shows the parameters used for estimating the cost of regasification of hydrogen.

Table 134: Parameters used for estimating the costs of regasification (Yang & Ogden, 2007)(Quirijns, 2015)

Parameter	Value	Unit
Capex (540000m^3)	800	M€
Lifetime	20	years
Interest rate	5	%
Opex	9	% of capex
Scaling factor	0.7	
Multiplier	150	%

As discussed in section 7.2.5, the regasification plants for liquid hydrogen are modelled after the Gate LNG terminal in Rotterdam. The Gate terminal has a capacity of 180000m^3 and an estimated cost of 800 M€(Quirijns, 2015). To account for the extra costs involved with hydrogen regasification, the costs are estimated at 150% of the costs required for a similar regasification plant for LNG. Table 135 shows the costs associated with the regasification of hydrogen and final cost of shipping with regasification at Rotterdam.

Table 135: Regasification costs for hydrogen shipping

Capacity, tons	Capex, M€	Capex, M€/yr	Opex, M€/yr	Total costs, M€/yr
10074	534.4	42.8	48.1	90.9

Apart from the costs of hydrogen produced in the Netherlands, import costs will have to be added to estimate the final system costs of hydrogen transported by road or pipeline. Liquid transport would have an import price of 127 €/MWh while gaseous hydrogen transport would have an import price of 128 €/MWh. Liquid storage costs have been previously estimated in section 8.2.1.

8.2.3 Pipeline transport

As discussed in section 7.2.6, the transport of hydrogen by pipeline involves multiple components other than the pipeline itself, which is depicted in figure 10 in the same section. As seen in the figure, the system costs of transporting hydrogen by pipelines would involve the costs of hydrogen produced from electrolyser with gaseous hydrogen storage, hydrogen import costs including regasification, compression and decompression costs, pipeline costs and gaseous storage costs at the destination.

To transport hydrogen by pipeline, compressors will be required to pressurize the hydrogen to its transport pressure and further give it enough kinetic energy to transport the hydrogen along the pipeline. The capacity of the compressors required for each transport route has already been modelled in the previous section and is listed in table 23. Table 136 shows the parameters used to estimate the cost of the compressors and the pipeline as well. Since only the equipment costs for compressors were available, it was decided to use a factor of 1.9 to account for the other direct and indirect costs of the compressors as discussed in section 8.1.

Table 136: Parameters used for calculating hydrogen pipeline and compressor costs (Yang & Ogden, 2007)(Lensink & Pisca, 2019)(Parker, 2004)

Parameter	**Value**	**Unit**
Lifetime of pipeline	50	years
Lifetime of compressor	20	years
Right of way	400000	€/km
Material cost factor	150	%
Compressor costs	1739	€/kW
Compressor scaling factor	0.9	
Opex	9	% of Capex
Electricity	0.07	€/kWh
Compressor Capex factor	190	% of compressor costs

The estimated costs of the modelled compressors, that will be used for transporting hydrogen by pipelines along the five routes is shown in table 137. Another assumption that is made in this thesis is that the decompressor at the end of the pipeline is assumed to be similar to the compressor at the beginning of the pipeline and thereby the costs are the same.

Table 137: Costs of compressors used for hydrogen pipeline transport

Route	**Compressor size, kW**	**Capex, M€**	**Electricity costs, M€/yr**	**Capex, M€/yr**	**Total cost, M€/yr**
Delfzijl - Emmen	263	0.6	0.2	0.04	0.2
Delfzijl - Amsterdam	1011	1.9	0.6	0.15	0.8
Rotterdam - Amsterdam	569	1.1	0.3	0.09	0.4
Rotterdam - Zeeland	3851	6.2	2.3	0.50	2.9
Rotterdam - Chemelot	3426 + 1937	8.9	3.3	0.72	4.0

Following this, the cost of pipeline has to be estimated. As discussed in section 7.2.6 and table 22, the costs of the pipeline varies according to the steel grades used. As a result the steel grade x65 was chosen, as it was most economical steel grade for all the routes except for the Delfzijl - Emmen route in which, x52 was estimated to be cheaper. The right of way costs refer to the costs incurred to purchase the land on which the pipeline will be built. Also mentioned in the same section, is the requirement for an additional coating called Galvalume to prevent hydrogen embrittlement and special seals to prevent leakage from the pipelines, which potentially will increase the pipeline and labour costs (Parker, 2004)(Weber et al., 2013). Since specific costs could not be realised for the special seals and Galvalume coated steel pipes, factors were used to justify the additional costs of constructing the pipeline, which has been listed in table 136. To estimate the labour cost of building the hydrogen pipeline, the following formula was used (Parker, 2004).

$$Labourcost = 1.25 * ((343 * (OD)^2 + 2074 * (OD) + 170013) * (l) + 185000) \qquad (23)$$

where, OD is the outer diameter of the pipeline in inches and l is the length of the pipeline in miles.

With the parameters and assumptions known, the final costs of the pipeline was estimated for each route. Table 138 shows the breakdown of the costs of the pipeline.

Table 138: Costs for transporting hydrogen by pipelines

Route	**Material cost, M€**	**Labour cost, M€**	**Right of way, M€**	**Capex (including compressor), M€/yr**	**Opex (including compressor), M€/yr**	**Total cost, M€/yr**
Delfzijl - Emmen	0.5	7.8	24.3	1.9	3.4	5.2
Delfzijl - Amsterdam	3.8	24.7	70.4	5.7	10.5	16.2
Rotterdam - Amsterdam	0.8	8.0	23.8	2.0	3.8	5.8
Rotterdam - Zeeland	4.1	12.9	25.3	3.3	9.7	13.0
Rotterdam - Chemelot	10.2	32.0	68.6	7.5	18.2	25.7
€/MWh						1

The €/MWh cost in table 138 does not represent the system costs for transporting hydrogen by pipeline, as it only includes the costs of the pipeline and the costs of the compressors for loading and unloading. To estimate the system costs, the cost of the hydrogen produced by the electrolyser including storage, the costs of hydrogen imported by ship and the costs of storing hydrogen at the destination have to be included. This will be estimated at the end of this section.

8.2.4 Compressed road transport

The system components involved in the transport of compressed hydrogen by road are similar to that of pipeline transport except for the transport medium - tube trailers. The system boundaries can be seen in figure 11. Compressed hydrogen is transported on road by composite tube trailers which operate at three different transport pressures, as previously discussed in section 7.2.7. Table 139 lists the parameters used for estimating the costs for compressed road transport.

Table 139: Parameters used to estimate the cost of compressed hydrogen road transport (Yang & Ogden, 2007)(Wulf & Zapp, 2018)(Botero, 2018)

Parameter	**Value**	**Unit**
Lifetime of tube trailer	6	years
Maintenance	6	% of Capex
Tyres	4	% of Capex
Insurance	3	% of Capex
Driver wages	35	€/hr
Diesel	1.35	€/litre

The parameters is assumed to remain the same for all three tube trailers eventhough they differ in dimensions and weight. The Capex and the loading capacities vary for the tube trailers and thereby, the number of tube trailers required would change. Table 140 shows the Capex of the tube trailers, including the cost of the prime mover.

Table 140: Capex of hydrogen tube trailers (Baldwin, n.d.)

Type	**Capex, €**	**Capacity, kg**
250 bar	529550	900
350 bar	663050	1050
500 bar	1152550	1500

In section 7.2.7, the number of tube trailers required for each route have been estimated taking into account the capacity of each tube trailer and the loading and unloading times. Using this result, the costs for transporting hydrogen at 250, 350 and 500 bar was estimated and is shown in table 141, 142 and 143, respectively. Other Opex refers to the costs incurred for the maintenance, insurance and tyre replacements related to the tube trailer.

Table 141: Estimated costs for transporting hydrogen by 250 bar tube trailers

Road routes	**Driver wages, €/trip**	**Fuel costs, €/trip**	**Other Opex, €/trailer**	**Capex, M€**	**Opex, M€/yr**	**Capex M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	280	66	68842	18.5	15.7	3.7	19.3
Delfzijl - Amsterdam	455	192	68842	210.2	121.1	41.4	162.5
Rotterdam - Amsterdam	245	65	68842	36.7	30.6	7.8	38.4
Rotterdam - Zeeland	280	72	68842	267.4	229.3	52.7	281.9
Rotterdam - Chemelot	420	155	68842	356.4	328.7	70.2	398.9

Table 142: Estimated costs for transporting hydrogen by 350 bar tube trailers

Road routes	**Driver wages, €/trip**	**Fuel costs, €/trip**	**Other Opex, €/trailer**	**Capex, M€**	**Opex, M€/yr**	**Capex M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	280	66	86197	19.9	13.9	3.9	17.9
Delfzijl - Amsterdam	455	192	86197	222.1	108.0	43.8	151.7
Rotterdam - Amsterdam	245	65	86197	41.8	26.8	8.2	35.0
Rotterdam - Zeeland	280	72	86197	281.8	200.3	55.5	255.8
Rotterdam - Chemelot	420	155	86197	375.9	286.7	74.1	360.8

Table 143: Estimated costs for transporting hydrogen by 500 bar tube trailers

Road routes	**Driver wages, €/trip**	**Fuel costs, €/trip**	**Other Opex, €/trailer**	**Capex, M€**	**Opex, M€/yr**	**Capex M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	280	66	149832	24.2	11.1	4.8	15.9
Delfzijl - Amsterdam	455	192	149832	270.8	90.7	53.4	144.1
Rotterdam - Amsterdam	245	65	149832	50.7	21.5	10.0	31.5
Rotterdam - Zeeland	280	72	149832	343.5	159.4	67.7	227.1
Rotterdam - Chemelot	420	155	149832	457.6	226.0	90.1	316.2

Similar to pipeline transport, compressors are an integral part of the system, as hydrogen has to be compressed to the different transport pressures of 250, 350 and 500 bar. The capacities of the compressors have been modelled in section 7.2.7, and is shown in table 28. The parameters that will be used to estimate the costs of the compressors required for 250, 350 and 500 bar tube trailers, is listed in table 144. This is followed by the detailed cost breakdown of the compressor including the number of compressors that would be required for each route, which is shown in table 145, 146 and 147.

Table 144: Parameters used for estimate the costs of compressors used for hydrogen road transport (Yang & Ogden, 2007)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Compressor capacity (250 bar)	1252	kW
Compressor capacity (350 bar)	1819	kW
Compressor capacity (500 bar)	3363	kW
Compressor costs (250 bar)	1.3	M€
Compressor costs (350 bar)	1.9	M€
Compressor costs (500 bar)	3.3	M€
Opex	4	% of compressor costs
Lifetime	20	years
Electricity	0.07	€/kWh
Compressor Capex factor	190	%

Table 145: Compressor costs for transporting hydrogen in 250 bar tube trailers

Route	**No. of compressors**	**Capex, M€**	**Electricity costs, M€/yr**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	35	89.3	26.9	28.8	7.2	35.9
Delfzijl - Amsterdam	397	1013.4	304.8	326.2	81.3	407.5
Rotterdam - Amsterdam	75	191.4	57.6	61.6	15.4	77.0
Rotterdam - Zeeland	505	1289.0	387.8	414.9	103.4	518.3
Rotterdam - Chemelot	673	1717.9	516.8	552.9	137.8	690.8

Table 146: Compressor costs for transporting hydrogen in 350 bar tube trailers

Route	**No. of compressors**	**Capex, M€**	**Electricity costs, M€/yr**	**Opex costs, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	30	107.2	33.5	35.7	8.6	44.3
Delfzijl - Amsterdam	335	1196.6	373.6	398.8	96.0	494.8
Rotterdam - Amsterdam	63	225.0	70.3	75.0	18.1	93.1
Rotterdam - Zeeland	425	1518.0	474.0	506.0	121.8	627.8
Rotterdam - Chemelot	567	2025.2	632.4	675.0	162.5	837.6

Table 147: Compressor costs for transporting hydrogen in 500 bar tube trailers

Route	**No. of compressors**	**Capex, M€**	**Electricity costs, M€/yr**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	21	130.4	43.3	46.1	10.5	56.5
Delfzijl - Amsterdam	235	1459.4	484.6	515.3	117.1	632.4
Rotterdam - Amsterdam	44	273.3	90.7	96.5	21.9	118.4
Rotterdam - Zeeland	298	1850.7	614.5	653.5	148.5	802.0
Rotterdam - Chemelot	397	2465.5	818.7	870.6	197.8	1068.4

An interesting observation from the table above, is that even when the number of compressors decrease as higher pressure tube trailers are used, the total costs still increase. This is due to the increase in compressor capacities as the transport pressure increases. With the compressor, decompressor and tube trailer costs known, the transport costs was estimated to be 96 €/MWh for 250 bar, 110 €/MWh for 350 bar and 134 €/MWh for 500 bar. Despite the decreasing number of tube trailers required at higher pressures, the costs of the transport medium increases. This is due to the increase of the Capex of the tube trailers as the pressure increases and increase in compressor costs as compressor capacities increase.

8.2.5 Liquid road transport

As discussed in section 7.2.8, the system components involved in the transport of liquid hydrogen by road varies with respect to compressed hydrogen road transport. Additional components of liquefaction and regasification of hydrogen is required at the source and destination, respectively. Another difference, is that the hydrogen imported does not have to be regasified, instead liquid hydrogen storage will be required at the port of Rotterdam. Regasification plants also includes storage for the liquid energy carrier. The first system component involved in the transport of liquid hydrogen, after the hydrogen electrolyser is the liquefaction plant. As discussed in section 7.2.8, the source for hydrogen transport is from Delfzijl and Rotterdam and thereby liquefaction plants will be required at both these locations. Further, the liquid hydrogen imports coming in via the port of Rotterdam, serves as an advantage for liquid hydrogen transport, as the liquid hydrogen could be loaded directly onto the road tankers eliminating the need for a liquefaction plant. This results in a smaller liquefaction plant required at Rotterdam. The parameters used to estimate the costs of the liquefaction plants have been previously discussed, when estimating the costs of liquefaction plants for maritime transport of hydrogen and thereby can be found in table 132. Table 148 lists the liquefaction costs estimated at the source.

Table 148: Liquefaction costs at Delfzijl and Rotterdam

Industrial cluster	**Plant size, ton/day**	**Capex, M€**	**Electricity cost, M€/yr**	**Opex costs, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Delzijl	554	579.3	76.6	23.2	46.5	146.2
Rotterdam	2232	1466.7	308.4	58.7	117.7	484.8

As discussed in section 7.2.8, liquid hydrogen will be transported by steel road tankers. The number of road tankers needed and the time taken for each trip have also been estimated in the same section. The parameters used for estimating the cost of liquid hydrogen transport is similar to that of compressed hydrogen road transport and thereby can be found in table 139. The steel tanker chosen for this thesis has a Capex of 930000 €, including the cost of the prime mover (Wulf & Zapp, 2018)(Botero, 2018). Table 149 shows the costs of transporting liquid hydrogen by steel road tankers.

Table 149: Estimated costs of steel road tankers for transporting liquid hydrogen

Road routes	Driver wages, €/trip	Fuel costs, €/trip	Other Opex, €/trailer	Capex, M€	Opex, M€/yr	Capex M€/yr	Total costs, M€/yr
Delfzijl - Emmen	560	66	149831.5	20.5	7.7	4.0	11.7
Delfzijl - Amsterdam	735	192	149831.5	76.3	37.7	15.0	52.7
Rotterdam - Amsterdam	525	65	149831.5	43.7	15.8	8.6	24.4
Rotterdam - Zeeland	560	72	149831.5	290.2	109.7	57.2	166.8
Rotterdam - Chemelot	700	155	149831.5	257.6	119.9	50.8	170.7

To be able to utilise the hydrogen transported by the steel tankers, liquid hydrogen has to be regasified in regasification plants at the destination. The regasification plants have been modelled in section 7.2.8 and the cost of the plants can be seen in table 150. The parameters used to estimate the costs are similar to that done for maritime transport and thereby can be found in table 134.

Table 150: Estimated regasification costs at the destination

Industrial cluster	Capacity, tons/day	Capex, M€	Opex costs, M€/yr	Capex, M€/yr	Total costs, M€/yr
Emmen	92	19.9	1.8	1.6	3.4
Amsterdam	549	78.6	7.1	6.3	13.4
Zeeland	1337	132.6	11.9	10.6	22.6
Chemelot	1190	119.8	10.8	9.6	20.4

The final system component for which the costs have to be estimated for, are the pumps required to unload and load liquid hydrogen. The pump capacities have been modelled in the previous section and can be found in table 33. The parameters used to estimate the costs of the pumps is shown in table 151 and the estimated costs of pumps is shown in table 152.

Table 151: Parameters used for estimating liquid hydrogen pump costs (Loh et al., 2002)(Lensink & Pisca, 2019)

Parameter	Value	Unit
Pump size	176	kW
Capex	1884	/kW
Opex,	4	% of Capex
Lifetime	20	years
Electricity costs	0.07	€/kWh

Table 152: Estimated costs of liquid hydrogen pumps

Route	No. of pumps	Capex, M€	Electricity costs, M€/yr	Opex, M€/yr	Capex, M€/yr	Total costs, M€/yr
Delfzijl - Emmen	21	10.1	2.4	2.8	0.8	3.6
Delfzijl - Amsterdam	235	37.7	8.9	10.4	3.0	13.4
Rotterdam - Amsterdam	44	21.6	5.1	5.9	1.7	7.7
Rotterdam - Zeeland	298	143.5	33.7	39.5	11.5	51.0
Rotterdam - Chemelot	397	127.4	30.0	35.1	10.2	45.3

Therefore the cost of transporting liquid hydrogen by road which includes; liquefaction of hydrogen at the source, loading onto the tanker, transporting liquid hydrogen by steel road tankers, unloading from the tankers and regasifying liquid hydrogen at the destination was estimated to be 30 €/MWh.

8.2.6 System costs of hydrogen transport

The system costs are estimated based on the costs of the individual components in the system boundaries with respect to the mass of hydrogen transported. This is shown in table 153. The loading and unloading costs have been added to the transport medium costs and the import costs refer to the shipping costs of hydrogen from abroad. For the case of liquid hydrogen transport, the cost of liquefaction and regasification is also included in the cost for the transport medium.

Table 153: Estimated system costs of hydrogen transport

Transport medium	Production, €/MWh	Storage, €/MWh	Transport medium, €/MWh	Import, €/MWh	System costs, €/MWh
Pipeline	153	9	1	128	151
Compressed road - 250 bar	153	9	96	128	246
Compressed road - 350 bar	153	9	110	128	260
Compressed road - 500 bar	153	9	134	128	284
Liquid road	153	4	30	127	175

From the table, it can be concluded that pipelines are the most economical transport mode for hydrogen transport, followed by liquid hydrogen road transport and compressed hydrogen road transport. This is in line with the costs estimated by other reports (Yang & Ogden, 2007)(IEA, 2019). As discussed previously, compressed hydrogen road transport costs increase as higher pressure tube trailers are used. This is a good justification as to why using high pressure tube trailers may not necessarily decrease the costs of hydrogen delivered, even if the quantity of hydrogen delivered per tube trailer is higher. Analysing the individual components, the storage costs are negligible compared to the rest of the components while production and import costs dominate. The transport costs also go unnoticed in the case of pipeline and liquid hydrogen transport.

8.3 Ammonia transport

The first system component modelled for the transport of ammonia is the ammonia production plant which has been discussed in section 7.3. As mentioned in the same section, the renewable production of ammonia consists of hydrogen electrolysers, an air separation unit and the synloop unit. Since the costs of hydrogen electrolysers have already been estimated, only the cost for the air separation unit and the synloop unit have to be estimated. The parameters used for estimating the costs of ammonia production plants are listed in table 154.

Table 154: Parameters used for estimating the costs of ammonia production plants (Bartels, 2008)(Lensink & Pisca, 2019)(Frattini et al., 2016)

Parameter	**Value**	**Unit**
Capex ASU (10 ton/day) - 2008	5.0	M€
Capex synloop (10 ton/day) - 2008	6.6	M€
Scaling factor	0.65	
Opex	8	% of capex
Electricity costs	0.07	€/kWh
Operating capacity	80	%
Lifetime	20	years
Interest rate	5	%

The Capex of the ASU and synloop used here, is based on the report from Bartel et.al, while the Opex has been assumed to be 8% of the Capex as a general estimation (Bartels, 2008). Using the parameters above, the Capex, Opex and the electricity costs were estimated based on the ammonia plants modelled in section 7.3.

Table 155: Ammonia production costs

Industrial cluster	**Ammonia production, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Cost of electricity, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam	6421	773.2	64.8	109.4	65.0	239.3
Amsterdam	5929	734.2	61.6	101.0	61.7	224.3
Delfzijl	2054	368.5	30.9	35.0	31.0	96.9
Zeeland	2169	381.9	32.0	37.0	32.1	101.1

The cost of ammonia production including hydrogen production costs is estimated to be 171 €/MWh.

8.3.1 Ammonia reforming

Reforming of ammonia is based on autothermal reforming, which is a high temperature endothermic decomposition reaction as discussed in section 7.3.1. The parameters used to estimate the costs of ammonia reforming plants are listed in table 156. The ammonia reforming plant capacities have already been modelled in section 7.3.1.

Table 156: Parameters used for estimating the costs of cracking ammonia (Bartels, 2008)(Lensink & Pisca, 2019)(IEA, 2019)

Parameter	Value	Unit
Capex (1500 kton/yr)	460	M€
Opex	8	% of capex
Scaling factor	0.65	
Electricity costs	0.07	€/kWh
Interest rate	5	%
Lifetime	20	years
Hydrogen cost	5.85	€/kgH_2

The Capex used here was based on a 1500 kton/yr ammonia reformer that was modelled in a report by IEA, while the Opex was assumed to be 8% (IEA, 2019). With the parameters known, the costs of the ammonia reformer plants was estimated and the final costs are shown in table 157. Hydrogen combusted costs are based on costs of hydrogen delivered by pipeline, which was estimated to be 151 €/MWh.

Table 157: Estimated costs of ammonia reformer plants

Industrial cluster	**Plant capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Hydrogen combusted, M€/yr**	**Capex, M€/yr**	**Total cost, M€/yr**
Rotterdam	4701	502.0	161.8	680.9	162.3	761.4
Amsterdam	3338	401.8	129.6	483.5	129.9	547.9
Delfzijl	195	370.7	20.4	28.2	20.5	38.4
Zeeland	2949	269.8	119.5	427.1	119.9	486.5
Chemelot	1808	63.4	87.0	261.9	87.2	305.1
Emmen	139	50.9	16.4	20.1	16.5	28.3

As discussed in section 7.3.1, the ammonia reformer plant is solely based on hydrogen combustion and thereby electricity costs are eliminated. On the other hand, expensive hydrogen is lost in the process of reforming ammonia. The cost of the ammonia reformer plants is estimated to be 72 €/MWh.

8.3.2 Ammonia storage

Ammonia is stored as a liquid at -33°C in low-temperature storage tanks as discussed in section 7.3.2. The parameters used to estimate the costs of ammonia storage are listed in table 158.

Table 158: Parameters used for estimating the costs of storing ammonia (Bartels, 2008)(Songhurst, 2018)

Parameter	Value	Unit
Capex of 25 kton storage	20.6	M€
Scaling factor	0.7	
Opex	9	% of capex
Interest rate	5	%
Lifetime	20	years

Similar to ammonia production, the Capex has been based on the report from Bartel et.al, while the Opex was estimated to be 9% based on LNG storage from the report of Songhurst et.al, (Bartels, 2008)(Songhurst, 2018). Ammonia storage is to be placed after the production of ammonia at the source, at the import terminal at Rotterdam and also at the destination. With the parameters known, the cost of low-temperature ammonia storage was estimated. The €/MWh cost for each storage area is listed in table 159, 160 and 161.

Table 159: Estimated costs of storing ammonia at the ammonia production plants

Industrial cluster	Storage capacity, tons/day	Capex, M€	Opex costs, M€/yr	Capex, M€/yr	Total cost, M€/yr
Rotterdam	6421	8.0	0.7	0.6	1.4
Amsterdam	5929	7.5	0.7	0.6	1.3
Delfzijl	2054	3.6	0.3	0.3	0.6
Zeeland	2169	3.7	0.3	0.3	0.6
€/MWh					0.1

Table 160: Estimated costs of storing ammonia at the import terminal at the port of Rotterdam

Industrial cluster	Storage capacity, tons/day	Capex, M€	Opex, M€/yr	Capex, M€/yr	Total cost, M€/yr
Rotterdam	51757	34.3	3.1	2.8	5.8
€/MWh					0.05

Table 161: Estimated costs of storing ammonia at the destination

Industrial cluster	Storage capacity, tons/day	Capex, M€	Opex, €/yr	Capex, M€/yr	Total cost, M€/yr
Emmen	644	1.6	0.1	0.1	0.3
Amsterdam	9509	10.5	0.9	0.8	1.8
Zeeland	11468	12.0	1.1	1.0	2.0
Chemelot	8363	9.6	0.9	0.8	1.6
€/MWh					0.08

As seen in the tables, the cost of ammonia storage is very low and is not expected to contribute much to the final costs of the transport system.

8.3.3 Maritime shipping

As discussed in section 7.3.3, ammonia is transported by LPG ships over oceans, and thereby the transport costs are modelled after LPG ships. Similar to LNG ships, LPG ships are chartered and not owned by companies. Thereby the costs of chartering a ship on a daily basis is used and not the costs of the buying a new ship. The other costs associated with maritime shipping include insurance, maintenance, fuel charges, port charges and manning costs. Table 162 lists the parameters used for estimating the shipping costs of ammonia.

Table 162: Parameters used for estimating ammonia maritime shipping costs (Dobrota et al., 2013)(Polemis, 2013)(Rodrigue et al., 2017)(Rogers, 2018)(BW LPG, n.d.)

Parameter	**Value**	**Unit**
Charter rate	13172	€/day
Port charges	1500000	€/year
Manning charges	500000	€/year
Boil-off loses	0.12	%/day
Maintenance & repair	300000	€/year
Insurance	500000	€/year
Fuel costs	380	€/ton

Some of the parameters used here are similar to that of LNG ships, like the port charges, insurance, maintenance, manning and fuel costs. These parameters are not expected to vary much between LNG and LPG ships. Taking into account the parameters listed in table 162, the costs of shipping ammonia over a distance of 8000 km was estimated and is shown in table 163.

Table 163: Estimated cost breakdown of ammonia shipping

Parameter	**Costs, €/trip**
Charter rate	171236
Port charges	12329
Manning charges	17808
Maintenance & repair	10685
Insurance	17808
Fuel costs	142191
Total costs	372057

The costs listed in table 163 are for a single trip and in the case of ammonia, one LPG ship has to be chartered every day for a year. Therefore 365 trips have to be made annually, which results in a cost of 136 M€. The cost of renewable ammonia sold at the port of source was estimated to be 116 €/MWh, which added to the cost of shipping results in a cost of 117 €/MWh (IEA, 2019). This cost still does not account for the costs of ammonia lost when shipping, which when added brings the estimated cost of shipping ammonia to the port of Rotterdam to be 118 €/MWh. The final cost of ammonia at the port of Rotterdam will also have to include the costs of storing ammonia at the port, which has a cost of 0.05 €/MWh. Therefore, the final costs of ammonia at the port of Rotterdam is estimated to be 118 €/MWh.

8.3.4 Pipeline transport

Ammonia will be transported by carbon steel pipelines as discussed in section 7.3.4. As seen in the same section, x65 is the most economical steel grade along all transport routes except for the Delfzijl - Emmen route for which the x70 steel grade is more economical. To transport ammonia by pipeline, pumps are used to pressurise ammonia to the required transport pressure, providing enough kinetic energy to transport ammonia along the pipeline. Table 164 lists the parameters required to estimate the costs of the pumps and also the pipeline itself. Since only the equipment costs for pumps were available, it was decided to use a factor of 1.9 to account for the other direct and indirect costs of the pumps as discussed in section 8.1.

Table 164: Parameters used for estimating ammonia pipeline and pump costs (Loh et al., 2002)(Yang & Ogden, 2007)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Lifetime of pipeline	50	years
Lifetime of pump	20	years
Right of way	400000	€/km
Pump costs	1883.7	€/kW
Pump scaling factor	0.9	
Opex of the pipeline	9	% of Capex
Electricity	0.07	€/kWh
Pump Capex factor	190	% of pump Capex

Another assumption made, similar to hydrogen pipeline transport, is that the unloading costs is assumed to be similar to the loading costs. With the parameters known, the costs of the pumps was estimated and this is show in table 165.

Table 165: Estimated costs of pumps used for ammonia pipelines

Route	**Pump size, kW**	**Capex, M€**	**Electricity costs, M€/yr**	**Capex, M€/yr**	**Total cost, M€/yr**
Delfzijl - Emmen	4091	7.8	2.5	0.6	3.1
Delfzijl - Amsterdam	3242	6.3	2.0	0.5	2.5
Rotterdam - Amsterdam	57223	83.7	35.1	6.7	41.8
Rotterdam - Zeeland	72922	104.1	44.7	8.4	53.1
Rotterdam - Chemelot	53175 + 30884	126.4	51.5	10.1	61.7

Similar to hydrogen pipeline transport, the labour, material and right of way costs of building the pipeline was estimated. Labour costs of ammonia pipelines was estimated using equation 23 without the hydrogen labour cost factor of 1.25. Table 166 shows the final costs of the pipeline, which includes the pump as well.

Table 166: Estimated pipeline costs for transporting ammonia

Route	**Material costs, M€**	**Labour costs, M€**	**Right of way, M€**	**Capex (including pump), M€/yr**	**Opex (including pump), M€/yr**	**Total cost, M€/yr**
Delfzijl - Emmen	0.7	6.4	24.3	3.0	9.2	12.2
Delfzijl - Amsterdam	3.3	19.1	70.4	6.1	13.5	19.6
Rotterdam - Amsterdam	4.3	8.9	23.8	15.5	88.6	104.1
Rotterdam - Zeeland	5.9	10.3	25.3	19.0	111.9	130.9
Rotterdam - Chemelot	12.5	25.6	68.6	26.1	135.4	161.6
€/MWh						6

The Opex dominates the pipeline costs relative to the Capex. This indicates that operating the pipeline is more expensive than erecting the pipeline itself. 6 €/MWh is only the transport costs and not the system cost. The system costs for ammonia pipeline transport will include ammonia production costs, storage costs at the source and destination, import costs and ammonia reformer costs.

8.3.5 Road transport

Ammonia is transported by road as a liquid pressurised at 10 bar, using T-10 tank containers. As discussed in section 7.3.5, 10 tons of ammonia can be transported using the T-10 tank containers in a single trip. The number of trips required by each tank container followed by the number of tank containers required for each route was estimated in section 7.3.5. Using these estimates, the cost of the tank containers and the pumps was estimated as is shown in table 168. The parameters used to estimate the costs of the tank containers are listed in table 167.

Table 167: Parameters used for estimating tank container costs (Yang & Ogden, 2007)(Wulf & Zapp, 2018)(Botero, 2018)

Parameter	**Value**	**Unit**
Lifetime of tank containers	6	years
Capex of T-10 Tank container	115000	€
Maintenance	6	% of Capex
Tyres	4	% of Capex
Insurance	3	% of Capex
Driver wages	35	€/hr
Diesel	1.35	€/litre

Table 168: Estimated costs of ammonia tank containers

Route	Driver wages, €/trip	Fuel costs, €/trip	Other Opex, €/tankcontainer	Capex, M€	Opex, M€/yr	Capex, M€/yr	Total costs, M€/yr
Delfzijl - Emmen	280	66	14950	2.5	8.7	0.5	9.2
Delfzijl - Amsterdam	455	192	14950	5.9	12.8	1.2	14.0
Rotterdam - Amsterdam	245	65	14950	34.6	106.6	6.8	113.4
Rotterdam - Zeeland	280	72	14950	44.0	153.2	8.7	161.9
Rotterdam - Chemelot	420	155	14950	48.2	182.0	9.5	191.5

Similar to hydrogen road transport, other Opex refers to the maintenance, tyres and insurance of the tank containers. To load the tank containers at 10 bar, pumps have to be used. The capacity of the pump required to load the tank containers has been already modelled in section 7.3.5. Thereby the costs for loading and unloading the tank containers was estimated. The parameters used to estimate the costs of the pumps are listed in table 169.

Table 169: Parameters used for estimating ammonia pump costs (Loh et al., 2002)(Lensink & Pisca, 2019)

Parameter	Value	Unit
Pump size	139	kW
Pump costs	1884	€/kW
Opex	4	% of pump costs
Lifetime	20	years
Electricity costs	0.07	€/kWh
Pump Capex factor	190	% of pump Capex

Similar to ammonia pipeline transport, only the cost of the pump could be found and thereby a factor of 1.9 was used to estimate the Capex of the pump. The costs of the pumps were estimated and is shown in table 170. Similar to ammonia pipeline transport, the unloading costs are assumed to be similar to the loading costs.

Table 170: Estimated costs of ammonia pumps for ammonia road transport

Route	No. of pumps	Capex, M€	Electricity cost, M€/yr	Opex, M€/yr	Capex, M€/yr	Total costs, M€/yr
Delfzijl - Emmen	22	8.2	1.9	2.2	0.7	2.9
Delfzijl - Amsterdam	51	18.9	4.3	5.1	1.5	6.6
Rotterdam - Amsterdam	301	111.5	25.6	30.1	9.0	39.0
Rotterdam - Zeeland	383	141.9	32.6	38.3	11.4	49.6
Rotterdam - Chemelot	419	155.3	35.6	41.8	12.5	54.3

With both the costs of the pumps and tank containers known, the total cost of transporting ammonia by road was estimated. The costs of loading, transporting and unloading ammonia was estimated to be 12 €/MWh. Analysing table 168 and 170, the costs of loading and unloading are approximately $\frac{1}{3}$rd the costs of the tank containers. This indicates, that the costs of the tank containers forms a majority of the transport costs.

8.3.6 System costs of ammonia transport

Since the transport costs have only been estimated in the previous sections, the system costs will be estimated in this section. The system costs for ammonia pipeline and ammonia road transport are shown in table 171.

Table 171: Estimated system costs of ammonia transport

Transport medium	**Production, €/MWh**	**Storage, €/MWh**	**Transport medium, €/MWh2**	**Reforming, €/MWh**	**Import, €/MWh**	**System costs, €/MWh**
Pipeline	171	0.2	6	72	118	211
Road	171	0.2	12	72	118	217

From the table, it can be noticed that ammonia pipelines and ammonia road transport costs are almost the same with a difference of only 6 €/MWh. Ammonia pipelines are more economical compared to road transport, which is in line with the general conclusion that pipelines are more economical than road transport for higher quantities and longer distances (Sashi Menon, 2005). Despite this, the difference between the costs is minimal, which could be attributed to the fact that ammonia pipelines operates at 10MPa compared to the tank containers that operate at 1MPa, which results in more expensive pumps used for pipelines compared to road transport.

8.4 Methanol transport

The system boundaries for the transport of methanol are similar to that of the transport of ammonia, which comprises of everything from the production of the energy carrier to reforming it back to hydrogen at the destination. Since hydrogen production costs have already been estimated, only the CO_2 costs and the methanol production costs have to be estimated. M.Fasihi et.al, reports that using solid sorbent DAC, CO_2 will have a cost of 220 €/tonCO_2 as discussed in section 7.4 (Fasihi et al., 2019). In this thesis, it is assumed that CO_2 is purchased and therefore CO_2 capture is not modelled. The parameters used to estimate the cost of methanol production are listed in table 172.

Table 172: Parameters used to estimate the costs of methanol production plants (Lensink & Pisca, 2019)(Fasihi et al., 2019)(Pérez-Fortes et al., 2016)

Parameter	**Value**	**Unit**
Capex (440 ktonCH_3OH/year) - 2016	220	M€
CO_2 costs	222	€/ton
Scaling factor	0.65	
Lifetime	20	years
Opex	8	% of Capex
Electricity costs	0.07	€/kWh
Interest rate	5	%

Methanol production capacities have already been modelled in section 7.4 based on the reports by Perez-Fortes et.al, (Pérez-Fortes et al., 2016). The Capex for the methanol production plants have been based on on a 440 kton/yr methanol plant while the Opex is assumed to be 8 % of the Capex. With the parameters established, the cost of methanol production was estimated, which is shown in table 173.

Table 173: Estimated methanol production costs

Industrial cluster	**Methanol plant capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Electricity costs, M€/yr**	**Hydrogen combusted, M€/yr**	**Capex, M€/yr**	**CO_2 costs, M€/yr**	**Total costs, M€/yr**
Rotterdam	6772	752.1	60.2	178.4	270.1	60.3	942.1	1502.7
Amsterdam	6254	714.1	57.1	164.7	249.4	57.3	870.0	1390.7
Delfzijl	2166	358.5	28.7	57.0	86.4	28.8	301.3	500.0
Zeeland	2288	371.5	29.7	60.3	91.3	29.8	318.3	526.5

The final cost of methanol production including hydrogen production costs is estimated to be 249 €/MWh.

8.4.1 Methanol reforming

As discussed in section 7.4.1, methanol will be reformed back to hydrogen by the steam reforming of methanol. The methanol reformer plants have been modelled in the same section, based on a 288 kg/day reformer proposed by Kim et.al, (Kim et al., 2019). The details of the plant and the parameters used to estimate the cost of the methanol reformer plant are listed in table 174 .

Table 174: Parameters used for estimating the costs of methanol reforming (Kim et al., 2019)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Cost for a 288kg/day plant	136673	€
Opex	8	% of capex
Electricity costs	0.07	€/kWh
Capex multipler	403	%
Scaling factor	0.65	
Interest rate	5	%
Lifetime	20	years

The model proposed by Kim et.al, only had the cost of the equipment, so to estimate the Capex of the methanol plant including the direct costs, indirect costs and the working capital, a factor of 4.3 was used. This assumption has been discussed earlier in section 8.1. The costs of the methanol reformers shown in table 175 were estimated based on the parameters listed in table 174.

Table 175: Estimated costs of methanol reformers

Industrial cluster	Plant capacity, tons/day	Capex, M€	Opex, M€/yr	Electricity costs, M€/yr	Hydrogen combusted, M€/yr	Capex, M€/yr	Total costs, M€/yr
Rotterdam	7075	84.9	2.5	39.0	108.7	6.8	157.0
Amsterdam	5024	68.0	2.0	27.7	77.2	5.5	112.3
Delfzijl	293	10.7	0.3	1.6	4.5	0.9	7.3
Zeeland	4438	62.7	1.9	24.5	68.1	5.0	99.5
Chemelot	2721	45.6	1.4	15.0	41.8	3.7	61.8
Emmen	209	8.6	0.3	1.2	3.2	0.7	5.3

The cost of the methanol reforming is estimated to be 10 €/MWh. In general, the cost of electricity and hydrogen has a large effect on the estimated cost of methanol reforming.

8.4.2 Methanol storage

Methanol is stored in tanks similar to petroleum products like diesel and petrol as discussed in section 7.4.2. The parameters used to estimate the costs of methanol storage are listed in table 176.

Table 176: Parameters used for estimating the costs of storing methanol (Songhurst, 2018)(Jackson & Ward, 2014)

Parameter	Value	Unit
Capex of 15000 gallon storage	96500	€
Scaling factor	0.7	
Opex	5	% of capex
Interest rate	5	%
Lifetime	20	years

The Capex is based on a 15000 gallon methanol storage taken from the report by Jackson, while the Opex is assumed to be 5% based on the fact the Opex for LNG storage tanks is 9%. The Opex for LNG storage tanks involves the costs of operating pumps for re-liquefaction which is not the case for methanol storage and thereby a lower Opex is assumed (Jackson & Ward, 2014)(Songhurst, 2018). Methanol is expected to be stored after production and before being reformed back to hydrogen at the destination. The €/MWh cost for storage at the source and destination at each industrial cluster was estimated and is listed in table 177, 178 and 179.

Table 177: Estimated costs of methanol storage tanks at the methanol production plants

Industrial cluster	Storage capacity, tons/day	Capex, M€	Opex, M€/yr	Capex, M€/yr	Total cost, M€/yr
Rotterdam	6772	3.2	0.2	0.3	0.4
Amsterdam	6254	3.1	0.25	0.3	0.4
Delfzijl	2166	1.5	0.1	0.1	0.2
Zeeland	2288	1.5	0.1	0.1	0.2
€/MWh					0.03

Table 178: Estimated costs of methanol storage tanks at the import terminal at the port of Rotterdam

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total cost, M€/yr**
Rotterdam	121651	24.4	1.2	2.0	3.2
€/MWh					0.01

Table 179: Estimated costs of methanol storage tanks at the destination

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total cost, M€/yr**
Emmen	969	0.83	0.1	0.1	0.1
Amsterdam	16983	6.2	0.3	0.5	0.8
Zeeland	18238	6.5	0.3	0.5	0.8
Chemelot	12587	5.0	0.3	0.4	0.7
€/MWh					0.02

Similar to ammonia, the storage costs are very low and is not expected to contribute much to the system costs of methanol transport.

8.4.3 Maritime shipping

As discussed in section 7.4.3, methanol is shipped by specialised tankers that are made from stainless steel or zinc. Similar to LPG and LNG ships, methanol tankers are also chartered on a daily basis and the other costs associated with maritime shipping include insurance, maintenance, fuel charges, port charges and manning costs. Listed in table 180 are the parameters used for estimating the costs of methanol shipping.

Table 180: Parameters used for estimating methanol maritime shipping costs (Grover, 2013)(Polemis, 2013)(Rodrigue et al., 2017)(Rogers, 2018)

Parameter	**Value**	**Unit**
Charter rate	12905	€/day
Port charges	1500000	€/year
Manning charges	3500	€/day
Maintenance & repair	2000	€/day
Insurance	700	€/day
Fuel costs	380	€/ton

Taking into account the parameters listed in table 180, the costs of shipping methanol over a distance of 8000 km was estimated and is shown in table 181.

Table 181: Methanol shipping cost breakdown

Parameter	**Costs, €/trip**
Charter rate	167765
Port charges	12329
Manning charges	45500
Maintenance & repair	26000
Insurance	9100
Fuel costs	142191
Total costs	402885

As discussed in section 7.4.3, 60826 tons of methanol can be shipped in one trip, but the daily demand for methanol is 73916 tons. Therefore, two methanol tankers have to be chartered every day resulting in 730 trips made every year. This has a total estimated cost of 588 M€. The cost of renewable methanol sold at the port of source was estimated to be 188 €/MWh, which added to the cost of shipping results in a cost of 190 €/MWh (Hank et al., 2018). The final costs of shipping methanol will also have to include the costs of methanol storage at the port of destination which is 0.01 €/MWh. Thereby the final estimated cost of shipping methanol is 190 €/MWh.

8.4.4 Pipeline transport

Methanol is transported as a liquid by carbon steel pipelines, similar to ammonia. As discussed in section 7.4.4, the x65 steel grade is the cost effective steel grade to use along all the transport routes. To load and transport methanol along the pipeline, pumps are required since methanol is transported as a liquid. Table 182 shows the parameters used to estimate the cost of methanol pipelines and pumps. Since only the equipment costs for pumps were available, it was decided to use a factor of 1.9 to account for the other direct and indirect costs of the pumps as discussed in section 8.1.

Table 182: Parameters used for estimating methanol pipeline and pump costs (Loh et al., 2002)(Yang & Ogden, 2007)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Lifetime of pipeline	50	years
Lifetime of pump	20	years
Right of way	400000	€/km
Pump costs	1883.7	€/kW
Pump scaling factor	0.9	
Opex of the pipeline	9	% of Capex
Electricity	0.07	€/kWh
Pump Capex factor	190	% of pump Capex

With the parameters known, the costs of methanol pumps used for pipeline transport were estimated and is shown in table 183.

Table 183: Estimated costs of methanol pumps

Route	**Pump size, kW**	**Capex, M€**	**Electricity costs, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	4023	7.7	2.5	0.6	3.1
Rotterdam - Amsterdam	84321	118.7	51.7	9.5	61.2
Rotterdam - Zeeland	90550	126.5	55.5	10.2	65.7
Rotterdam - Nijmegen	62493	90.6	38.3	7.3	45.6
Nijmegen - Chemelot	42859	64.5	26.3	5.2	31.5
Nijmegen - Emmen	537	1.3	0.3	0.1	0.4

Another assumption that is made is that the costs of pumps for loading is the same as the cost of unloading. Following the costs of methanol pumps, the costs of methanol pipelines were estimated. The pipeline material costs have already been estimated in section 7.4.4 and the labour costs involved in laying the pipeline can be estimated using equation 23 without using the hydrogen factor of 1.25. Table 184 shows the final costs of methanol pipelines for all the transport routes.

Table 184: Estimated pipeline costs for transporting methanol

Route	**Material costs, M€**	**Labour costs, M€**	**Right of way, M€**	**Capex (inlcuding pump), M€/yr**	**Opex (inlcuding pump), M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	1.2	6.7	24.3	3.0	9.2	12.2
Rotterdam - Amsterdam	6.9	10.7	23.8	21.3	128.5	149.8
Rotterdam - Zeeland	7.3	11.3	25.3	22.7	137.8	160.5
Rotterdam - Nijmegen	7.6	13.8	32.4	17.5	97.8	115.3
Nijmegen - Chemelot	10.5	16.1	36.2	13.8	69.8	83.6
Nijmegen - Emmen	1.1	14.1	55.6	4.1	7.3	11.3
€/MWh						5

The costs of the methanol pipeline as seen in table 184, reflect only the costs of the pumps for loading and unloading, and the costs of the pipeline. The system costs will have to include methanol production costs, storage costs at the source and destination, import costs and methanol reformer costs. In general, the pipeline costs are dominated by the Opex, while the Capex contribution is only noticeable along shorter routes like Delfzijl - Emmen or routes that transport very low quantities like Nijmegen - Emmen.

8.4.5 Road transport

Methanol is transported as a liquid by road using steel tankers. As discussed in section 7.4.5, 26000 litres of methanol can be transported using these tankers in a single trip. For reference, 26000 litres of methanol translates to 20.6 tons. The number of trips required by each steel tanker followed by the number of steel tankers required for each route was estimated in the section 7.4.5, now the cost of the steel tankers and the pumps can be directly estimated. The parameters used to estimate the costs of the steel tankers are listed in table 185 followed by the estimated costs of methanol steel tankers shown in table 186.

Table 185: Parameters used for estimating the costs of methanol steel tankers (Yang & Ogden, 2007)(Wulf & Zapp, 2018)(Botero, 2018)

Parameter	**Value**	**Unit**
Lifetime of tank containers	6	years
Capex of steel tanker	100000	€
Maintenance	6	% of capex
Tires	4	% of capex
Insurance	3	% of capex
Driver wages	35	€/hr
Diesel	1.35	€/litre

Table 186: Estimated costs of methanol steel tankers

Route	**Driver wages, €/trip**	**Fuel costs, €/trip**	**Other Opex, €/tanker**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	280	66	13000	1.4	5.5	0.3	5.8
Rotterdam - Emmen	455	193	13000	0.8	2.0	0.2	2.2
Rotterdam - Amsterdam	245	65	13000	27.5	96.9	5.4	102.3
Rotterdam - Zeeland	280	72	13000	29.6	117.8	5.8	123.7
Rotterdam - Chemelot	420	155	13000	30.6	132.3	6.0	138.4

Other Opex refers to the maintenance, tyres and insurance of the steel tankers. The next component for which the cost has to be estimated is for the loading and unloading of the steel tankers, which is done using pumps. The capacity of the pumps required to load the tankers have already been modelled and can be found in table 75. The parameters used to estimate the costs of the pumps are listed in table 187. Similar to methanol pipeline, a factor of 1.9 was used to estimate the Capex of the pump.

Table 187: Parameters used for estimating methanol pump costs (Loh et al., 2002)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Pump size	223	kW
Pump costs	1884	/kW
Opex,	4	% of capex
Lifetime	20	years
Electricity costs	0.07	€/kWh
Pump Capex factor	190	% of pump Capex

With the parameters known, the costs of the pumps were estimated, which is shown in table 188. Similar to pipeline transport of methanol, the unloading costs are assumed to be similar to the loading costs.

Table 188: Estimated costs of pumps for methanol road transport

Route	**No. of pumps**	**Capex, M€**	**Opex, M€/yr**	**Electricity cost, M€/yr**	**Capex, k€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	14	8.0	2.2	1.9	0.6	2.9
Rotterdam - Emmen	8	4.5	1.3	1.1	0.4	1.6
Rotterdam - Amsterdam	275	156.3	43.9	37.6	12.5	56.4
Rotterdam - Zeeland	296	168.2	47.2	40.5	13.5	60.7
Rotterdam - Chemelot	306	173.9	48.8	41.8	14.0	62.7

With both the costs of pumps and methanol steel tankers known, the costs of transporting methanol by road is estimated to be 7 €/MWh. Similar to ammonia road transport, the costs of the tanker dominates the transport costs, relative to the costs of pumps.

8.4.6 System costs of methanol transport

The costs of individual components for the transport of methanol have been estimated in the previous sub-sections. In this sub-section, the system costs for pipeline and road transport were estimated and is shown in table 189.

Table 189: Estimated system costs of methanol transport

Transport medium	**Production, €/MWh**	**Storage, €/MWh**	**Transport medium, €/MWh**	**Reforming, €/MWh**	**Import, €/MWh**	**System costs, €/MWh**
Pipeline	249	0.06	5	10	190	216
Road	249	0.06	7	10	190	218

Analysing the cost in table 189, it can be noticed that methanol pipelines and methanol road transport costs are almost the same with a difference of only 2 €/MWh. This difference is even less compared to that for ammonia transport. A reason for this is could be the change in the pipeline network, in which the Nijmegen - Emmen pipeline route adds additional costs to pipeline transport.

In the case of road transport, since the routes are direct and does not follow a fixed network, road is not affected much by the change in the transport routes. Overall, the transport, reforming and storage costs are almost negligible compared to the production and import costs.

8.5 DME Transport

The system components for DME are similar to that of ammonia including the transport modes used due to their very similar transport properties. The first system component that is modelled within the system boundaries of DME transport is the DME production plant. As previously discussed, the production of DME is based on methanol dehydration. Thereby, the cost of the methanol dehydration plant was estimated and then added onto the existing cost of methanol production, which has been modelled in section 8.4. The methanol dehydration plant has been modelled in section 7.5 based on the model discussed by Kiss A et.al, (Kiss et al., 2013). Table 190 lists the parameters used to estimate the cost of DME production.

Table 190: Parameters used to estimate the costs of DME production plants (Lensink & Pisca, 2019)(Michailos et al., 2019)(Kiss et al., 2013)(Fasihi et al., 2019)

Parameter	**Value**	**Unit**
Capex (100 ktonCH_3OCH_3/year) - 2013	1.26	M€
CO_2 costs	220	€/ton
Scaling factor	0.68	
Opex	8	% of Capex
Electricity costs	0.07	€/kWh
Interest rate	5	%
Lifetime	20	years

The Capex for the DME production plants have been based on a 100 kton/yr methanol dehydration plant while the Opex is assumed to be 8 % of the Capex (Kiss et al., 2013). With the parameters established, the production cost of DME was estimated and is shown in table 191.

Table 191: Estimated DME production costs

Industrial cluster	**DME plant capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Electricity costs, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam	2922	16.2	1.3	24.0	1.3	26.7
Amsterdam	2698	15.4	1.2	22.2	1.2	24.7
Delfzijl	935	7.7	0.6	7.7	0.6	8.9
Zeeland	987	8.0	0.6	8.1	0.6	9.4

The cost of DME production including methanol production costs is estimated to be 252 €/MWh.

8.5.1 DME reforming

Hydrogen will be produced from DME through the steam reforming of DME as discussed in section 7.5.1. Due to the similarities of the process of steam reforming of DME and methanol, steam reforming of DME was modelled after the steam reforming of methanol. The parameters used to estimate the costs of methanol steam reforming is listed in table 174 which can be found in section 8.4.1. As mentioned in the same section, the costs associated to the model proposed by Kim et.al, only has the equipment costs. Therefore to estimate the Capex of the DME reformer plant, a factor of 4.3 was used as discussed in section 8.1. Using the parameters listed in table 174, the cost of DME steam reforming was estimated and is shown in table 192.

Table 192: Estimated costs of DME decomposition plants

Industrial cluster	**Plant capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Electricity costs, M€/yr**	**Hydrogen combusted, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam	5087	84.9	2.5	39.0	108.7	6.8	157.0
Amsterdam	3612	68.0	2.0	27.7	77.2	5.5	112.3
Delfzijl	211	10.7	0.3	1.6	4.5	0.9	7.3
Zeeland	3191	62.7	1.9	24.5	68.1	5.0	99.5
Chemelot	1957	45.6	1.4	15.0	41.8	3.7	61.8
Emmen	151	8.6	0.3	1.2	3.2	0.7	5.3

The cost of DME reforming is estimated to be 10 €/MWh. Similar to methanol, the electricity costs and hydrogen costs dominated the reforming costs.

8.5.2 DME storage

DME is stored in storage tanks similar to ammonia and thereby modelled after the ammonia storage tanks in section 8.3.2. Therefore the parameters used to estimate the cost of DME storage tanks can be found in the same section. Storage tanks are expected to be at the source after the production of DME, at the import terminal at the port of Rotterdam and at the destination after transport. The costs for DME storage tanks for each area was estimated and is shown in table 193, 194 and 195.

Table 193: Estimated costs of DME storage tanks at the DME production plants

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam	2922	4.6	0.4	0.4	0.8
Amsterdam	2698	4.3	0.4	0.4	0.7
Delfzijl	935	2.1	0.2	0.2	0.4
Zeeland	987	2.1	0.2	0.2	0.4
€/MWh					0.09

Table 194: Estimated costs of DME storage tanks at the import terminal at the port of Rotterdam

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam	59287	37.8	3.4	3.0	6.4
€/MWh					0.03

Table 195: Estimated costs of DME storage tanks at the destination

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Delfzijl	41	0.23	0.1	0.1	0.1
Emmen	697	1.68	0.2	0.1	0.3
Amsterdam	14008	13.8	1.2	1.1	2.3
Zeeland	13770	13.6	1.2	1.1	2.3
Chemelot	9049	10.1	0.9	0.8	1.7
€/MWh					0.06

As seen in the tables, the cost of DME storage is very low and is not expected to contribute much to the system costs of DME transport.

8.5.3 Maritime shipping

As discussed in section 7.5.3, DME is shipped by LPG tankers and thereby the transport costs are modelled after LPG ships. LPG ships are chartered and not owned by companies, thereby the costs of chartering a ship is on a daily basis. The other charges associated with maritime shipping include insurance, maintenance, fuel charges, port charges and manning costs. Since ammonia is also transported using LPG ships, parameters used for estimating the shipping costs of DME can be found in table 162 in section 8.3.3. Taking into account the parameters listed in table 162, the costs of shipping DME over a distance of 8000 km was estimated and is shown in table 196.

Table 196: DME shipping cost breakdown

Parameter	**Costs, €/trip**
Charter rate	171236
Port charges	12329
Manning charges	17808
Maintenance & repair	10685
Insurance	17808
Fuel costs	142191
Total costs	372057

To be able to import 58168 tons of DME every day, one LPG ship has to be chartered every day. Chartering a LPG ship every day for a year results in 365 trips a year which has an estimated cost of 136 M€. The cost of renewable DME sold at the port of source was estimated to be 193 €/MWh, which added to the cost of shipping DME results in an estimated cost of 194 €/MWh (Michailos et al., 2019). This cost still does not account for the costs of boil-off losses while shipping, which when added brings the estimated cost of shipping DME to the port of Rotterdam to be 196 €/MWh. The final cost of transporting DME by ships will also include the costs of storing DME at the port of destination which was estimated to be 0.03 €/MWh. Therefore, the final estimated costs of shipping DME is 196 €/MWh.

8.5.4 Pipeline transport

DME is transported by pipeline in its liquid state using carbon steel pipes, as discussed in section 7.5.4. Table 88 in the same section shows that steel grade x65 is the most economical steel grade for all transport routes except for the Amsterdam to Delfzijl route, for which steel grade x52 is more economical. To pressurise and load DME onto the pipeline and transport it, pumps are required. Table 197 shows the parameters required to estimate the costs of DME pipelines and pumps. Similar to the other energy carriers, a factor of 1.9 is used to estimate the Capex of the pumps.

Table 197: Parameters used for estimating DME pipeline and pump costs (Loh et al., 2002)(Yang & Ogden, 2007)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Lifetime of pipeline	50	years
Lifetime of pump	20	years
Right of way	400000	€/km
Pump costs	1883.7	€/kW
Pump scaling factor	0.9	
Opex of the pipeline	9	% of Capex
Electricity	0.07	€/kWh
Pump Capex multiplier	190	% of pump Capex

With the parameters known, the cost of the pumps and the pipelines were calculated. It is also assumed that loading and unloading costs are similar. Table 198 shows the estimated cost of the pumps used for DME pipeline transport.

Table 198: Estimated costs of pumps used for DME pipelines

Route	**Pump size, kW**	**Capex, M€**	**Electricity costs, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam - Amsterdam	43752	65.8	26.8	5.3	32.1
Amsterdam - Delfzijl	125	0.3	0.1	0.1	0.1
Rotterdam - Zeeland	42883	64.6	26.3	5.2	31.5
Rotterdam - Nijmegen	30349	47.3	18.6	3.8	22.4
Nijmegen - Chemelot	28180	44.3	17.3	3.6	20.8
Nijmegen - Emmen	2168	4.4	1.3	0.4	1.7

To estimate the cost of DME pipelines, the material costs, labour costs, Right of way, Capex and Opex have to be estimated. The pipeline material costs have already been estimated in section 7.5.4 and the labour costs of building the pipeline can be estimated using equation 23 without using the factor of 1.25. The other costs can be estimated using the parameters listed in table 197 The final costs of the building and operating the pipeline is shown in table 199.

Table 199: Estimated pipeline costs for transporting DME

Route	**Material costs, M€**	**Labour costs, M€**	**Right of way, M€**	**Capex (inlcuding pump), M€/yr**	**Opex (inlcuding pump), M€/yr**	**Total costs, M€/yr**
Rotterdam - Amsterdam	5.6	9.8	23.8	12.7	69.0	81.7
Amsterdam - Delfzijl	0.6	17.2	70.4	4.9	8.2	13.0
Rotterdam - Zeeland	5.9	10.3	25.3	12.6	68.0	80.6
Rotterdam - Nijmegen	5.9	12.1	32.4	10.4	50.3	60.6
Nijmegen - Chemelot	6.6	13.5	36.2	10.2	47.6	57.8
Nijmegen - Emmen	2.6	15.1	55.6	4.7	10.1	14.8
€/MWh						3

As seen in table 199, DME pipeline transport costs was estimated to be 3 €/MWh. This includes the cost of the pumps for loading and unloading, and the cost of the pipeline. Following the similar trend of the pipeline transport of the other energy carriers, the Opex dominates the transport costs for DME pipelines as well.

8.5.5 Road transport

DME is transported by road using T-10 tank containers as a liquid pressurised to 10 bar. As discussed in section 7.5.5, 11 tons of DME can be transported by the tank containers in a single trip. To estimate the costs of the tank containers, the number of trips required by each tank container has to be estimated followed by the number of tank containers required for each route. This has already been estimated in section 7.5.5. Since the transport vehicle for DME and ammonia are the same, the parameters used to estimate the costs of the tank containers can be found in table 167 in section 8.3.5. Using these parameters, the costs of the tank containers were estimated, which is shown in table 200.

Table 200: Estimated costs of DME tank containers

Route	**Driver wages, €/trip**	**Fuel costs, €/trip**	**Other opex, €/tankcontainer**	**Cost of trucks, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam - Delfzijl	180	243	14950	0.5	1.2	0.1	1.3
Rotterdam - Emmen	143	193	14950	7.4	16.1	1.5	17.5
Rotterdam - Amsterdam	48	65	14950	48.9	150.5	9.6	160.2
Rotterdam - Zeeland	53	72	14950	48.1	167.2	9.5	176.7
Rotterdam - Chemelot	115	155	14950	47.4	179.0	9.3	188.3

The pumps that are used to load DME onto the tank containers at 10 bar have been modelled in section 7.5.5. The number of pumps required for each route is assumed to be equal to the number of tank containers that are used in each route. The parameters used to estimate the costs of the pumps are listed in table 201. This is followed by table 202, in which the costs of the pumps are shown.

Table 201: Parameters used for estimating DME pump costs (Loh et al., 2002)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Pump size	130	kW
Pump costs	1884	€/kW
Opex,	4	% of Capex
Lifetime	20	years
Electricity costs	0.07	€/kWh
Pump Capex factor	190	% of pump Capex

Table 202: Estimated costs of DME pumps for road transport

Route	**No. of pumps**	**Capex, M€**	**Opex, M€**	**Electricity costs, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam - Delfzijl	4	1.4	0.4	0.3	0.1	0.5
Rotterdam - Emmen	64	22.4	6.0	5.1	1.8	7.8
Rotterdam - Amsterdam	425	148.6	39.8	33.9	11.9	51.7
Rotterdam - Zeeland	418	146.1	39.2	33.3	11.7	50.9
Rotterdam - Chemelot	412	144.0	38.6	32.8	11.6	50.2

The costs of transporting DME by road is estimated to be 7 €/MWh, accounting for the costs of the pumps and the tank containers. In line with road transport of ammonia and methanol, the costs of the tankcontainers dominate the road transport costs.

8.5.6 System costs of DME transport

The system costs of DME pipeline and road transport was estimated in this section, and is shown in table 203.

Table 203: Estimated system costs of DME transport

Transport medium	**Production, €/MWh**	**Storage, €/MWh**	**Transport medium, €/MWh**	**Reforming, €/MWh**	**Import, €/MWh**	**System costs, €/MWh**
Pipeline	252	0.1	3	10	196	215
Road	252	0.1	7	10	196	220

The system costs follows the same trend as with the other energy carriers, where pipeline transport is more economical than road transport. The difference in costs is similar to ammonia but more compared to methanol, which could be attributed to the change in the transport network and routes. The storage, reforming and transport costs are negligible compared to the production and import costs, which follows suit with the other energy carriers.

8.6 Synthetic methane transport

The synthetic methane production plant is the first component within the system boundaries of synthetic methane transport. The cost of hydrogen production was already estimated in section 8.2, therefore only the cost of the synthetic production plant has to be estimated. As previously discussed in section 7.6, the synthetic methane production plant is modelled after a 3470 ton/yr plant designed and evaluated by Guilera et.al, (Guilera et al., 2018). The estimated cost of the synthetic methane plant will then be added to the hydrogen electrolyser costs. Table 204 lists the parameters used to estimate the cost of synthetic methane production.

Table 204: Parameters used to estimate the costs of synthetic methane production plants (Lensink & Pisca, 2019)(Guilera et al., 2018)(Fasihi et al., 2019)

Parameter	**Value**	**Unit**
Capex (3470 tonCH_4/year)	12.4	M€
CO_2 costs	222	€/ton
Scaling factor	0.65	
Opex	7.5	% of Capex
Electricity costs	0.07	€/kWh
Interest rate	5	%
Lifetime	20	years

The Capex for the synthetic production plants have been based on the same report by Guilera et.al, while the Opex is reported to be 7.5 % of the Capex (Guilera et al., 2018). With the parameters established, the production costs of synthetic methane was estimated which is shown in table 205.

Table 205: Estimated synthetic methane production costs

Industrial cluster	**Plant capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Electricity costs, M€/yr**	**Hydrogen combusted, M€/yr**	**Capex, M€/yr**	**CO_2 costs, M€/yr**	**Total costs, M€/yr**
Rotterdam	2262	433.7	32.5	638.6	14.3	34.8	502.8	1223.0
Amsterdam	2089	411.8	30.9	589.7	13.2	33.0	464.3	1131.1
Delfzijl	724	206.7	15.5	204.2	4.6	16.6	160.8	401.7
Zeeland	765	214.2	16.1	215.8	4.8	17.2	169.9	423.7

Synthetic methane production is estimated to have a cost of 250 €/MWh, which also includes the cost of hydrogen production.

8.6.1 Synthetic methane reforming

As discussed in section 7.6.1, synthetic methane will be reformed back to hydrogen by the steam reforming of synthetic methane. The reformer plants have already been modelled in the same section based on natural gas as an input, and thereby including a desulfurisation unit which is not necessary for the steam reforming of synthetic methane. Therefore, it has to be noted that the costs of the reformer plant will include the costs of the desulfurisation unit as well. The plants were modelled after a 197 tonH_2/day reformer proposed by Mondal et.al, (Mondal & Ramesh Chandran, 2014). The parameters used to estimate the cost of the synthetic methane reformer are listed in table 206.

Table 206: Parameters used for estimating the costs of synthetic methane reforming (Mondal & Ramesh Chandran, 2014)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Cost for a 197 tonH_2/day plant	341.3	M€
Opex	8	% of capex
Electricity costs	0.07	€/kWh
Scaling factor	0.65	
Interest rate	5	%
Lifetime	20	years

The costs of the synthetic methane reformers was estimated based on the parameters listed in table 206. The cost breakdown of the reformers are listed in table 207.

Table 207: Estimated costs of synthetic methane reformers

Industrial cluster	**Plant capacity, tons/day**	**Capex, M€**	**Opex, M€**	**Electricity costs, M€/yr**	**Hydrogen combusted, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Rotterdam	1563	755.6	60.5	14.9	154.3	60.6	290.2
Amsterdam	1110	604.9	48.4	10.5	109.6	48.5	217.0
Delfzijl	65	95.4	7.6	0.6	6.4	7.7	22.3
Zeeland	980	558.0	44.6	9.3	96.8	44.8	195.5
Chemelot	601	406.0	32.5	5.7	59.3	32.6	130.1
Emmen	46	76.7	6.1	0.4	4.6	6.2	17.3

The cost of the steam reforming of synthetic methane is estimated to be 36 €/MWh. In contrast to methanol and DME reforming, the cost of electricity is not dominant in synthetic methane reforming. The cost of hydrogen is dominant while the Capex and Opex have an equal effect towards the final costs of the steam reforming of synthetic methane.

8.6.2 Synthetic methane storage

For this thesis, synthetic methane is assumed to be stored in tanks similar to biomethane. The parameters used to estimate the costs of synthetic methane storage are listed in table 208.

Table 208: Parameters used for estimating the costs of storing synthetic methane (IRENA, 2013)(Krich et al., 2005)(P.E & Fernandez, 2013)

Parameter	**Value**	**Unit**
Capex of gaseous storage (31488 kg/day)	1230	€
Opex of gaseous storage	5	% of capex
Capex of liquid storage (11991 ton/day)	85	M€
Opex of liquid storage	9	% of capex
Scaling factor	0.7	
Interest rate	5	%
Lifetime	20	years

The Capex for gaseous storage is based on a 31488 kg/day biomethane storage taken from the report by IRENA while the Opex is assumed to be 5% based on the fact the Opex for LNG storage tanks is 9%. The Opex for LNG storage tanks involves the costs of operating pumps for re-liquefaction which is not the case for gaseous synthetic methane storage and thereby a lower Opex is assumed (Jackson & Ward, 2014)(Songhurst, 2018). The Capex for liquid storage was based on the report by P.E et.al, on a 11991 ton/day storage tank for LNG, while the Opex was estimated to be 9% for LNG tanks by Songhurst et.al, (P.E & Fernandez, 2013)(Songhurst, 2018). With the parameters known, the cost of synthetic methane storage was estimated. Synthetic methane is expected to be stored after production, at the import terminal at the port of Rotterdam, and before being cracked back to hydrogen at the destination. The costs for storage at the source and destination at each industrial cluster is listed in table 209, 210 and 211.

Table 209: Estimated costs of synthetic methane storage tanks at the production plants

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total cost, M€/yr**
Rotterdam	2262	194.7	9.7	15.6	25.4
Amsterdam	2089	184.1	9.2	14.8	24.0
Delfzijl	724	87.7	4.4	7.0	11.4
Zeeland	765	91.2	4.6	7.3	11.9
€/MWh					2

Table 210: Estimated costs of liquid synthetic methane storage tanks at the import terminal at the port of Rotterdam

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total cost, M€/yr**
Rotterdam	60100	263.2	23.7	21.1	44.8
€/MWh					0.5

Table 211: Estimated costs of synthetic methane storage tanks at the destination

Industrial cluster	**Storage capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total cost, M€/yr**
Emmen	635	80.0	4.0	6.4	10.4
Amsterdam	2834	228.0	11.4	18.3	29.7
Zeeland	3770	278.4	13.9	22.3	36.3
Chemelot	2780	224.9	11.2	18.0	29.3
€/MWh					2

As seen in the table, the cost of gaseous storage is high compared to liquid synthetic methane storage. The difference in costs, could be a result of the volume occupied by synthetic methane. For gaseous storage, synthetic methane is assumed to be stored at atmospheric pressure, while in liquid storage, synthetic methane is stored at -160°C. The density of synthetic methane is 0.656 kg/m^3 at atmospheric conditions and 422 kg/m^3 at cryogenic temperatures.

8.6.3 Maritime shipping

As discussed in section 7.6.3, synthetic methane is shipped as a liquid by LNG tankers. LNG tankers are assumed to be chartered on a daily basis while other costs associated with maritime shipping include insurance, maintenance, fuel charges, port charges and manning costs. Listed in table 212 are the parameters used for estimating the costs of synthetic methane shipping.

Table 212: Parameters used for estimating synthetic methane maritime shipping costs (Polemis, 2013)(Rodrigue et al., 2017)(Rogers, 2018)(Botero, 2018)

Parameter	**Value**	**Unit**
Charter rate	48950	€/day
Port charges	1500000	€/year
Manning charges	500000	€/year
Maintenance & repair	300000	€/year
Insurance	500000	€/year
Fuel costs	380	€/ton

Taking into account the parameters listed in table 212, the costs of shipping synthetic methane over a distance of 8000 km was estimated and is shown in table 213.

Table 213: Synthetic methane shipping cost breakdown

Parameter	**Costs, €/trip**
Charter rate	636350.00
Port charges	12329
Manning charges	17808
Maintenance & repair	10685
Insurance	17808
Fuel costs	227506
Total costs	922486

As discussed in section 7.6.3, 60100 tons of synthetic methane can be shipped in one trip but the daily demand for synthetic methane is 14348 tons. Therefore, one LNG tanker can be chartered every four days resulting in 92 trips made every year, which is estimated to cost 85 M€. The cost of renewable synthetic methane sold at the port of source was estimated to be 205 €/MWh, which added to the cost of shipping gives an estimated cost of 206 €/MWh (Guilera et al., 2018). Synthetic methane has to be liquefied before it can be loaded onto the LNG tanker, thereby the liquefaction costs have to be estimated. The parameters used to estimate the cost of liquefying hydrogen are listed in table 214. The liquefaction plant as discussed in section 7.6.3, is based on the Sabine pass liquefaction plant in the United states.

Table 214: Parameters used for estimating synthetic methane liquefaction costs (Songhurst, 2018)(Yang & Ogden, 2007)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Capex (61644 tons/day)	12193	M€
Opex	3	% of Capex
Scaling factor	0.57	
Electricity costs	0.07	€/kWh
Interest rate	5	%
Lifetime	20	years

Using the parameters listed above, the cost of liquefying synthetic methane was estimated and is shown in table 215. The daily capacity of the liquefaction plant was assumed to be 25% of the total capacity of the LNG tanker as the ship is chartered every four days. The plant is expected to operate at 80% of its total capacity to account for repairs and maintenance stops.

Table 215: Estimated synthetic methane liquefaction costs

Plant size, ton/day	Capex, M€	Output, ton/day	Electricity cost, M€/yr	Opex, M€/yr	Capex, M€/yr	Total costs, M€/yr
19799	6382.0	15839	356.0	160.0	512.1	1027.6

The liquefaction costs for synthetic methane was estimated to be 12 €/MWh, which added to the cost of synthetic methane and shipping, resulted in a final estimate of 217 €/kgH_2. This cost still does not account for the costs of synthetic methane lost when shipping, which when added brings the estimated cost to 220 €/MWh. At the port of Rotterdam, the costs of liquid storage or regasification has to be taken into account depending on how the synthetic methane will be further transported on land. If synthetic methane has to be transported as compressed gas through pipeline or road, regasification costs have to be included in the system costs, else only storage costs have to be included. Regasification plants include liquid storage as well. Table 216 shows the parameters used for estimating the cost of regasification of synthetic methane.

Table 216: Parameters used for estimating the costs of regasification (Yang & Ogden, 2007)(Quirijns, 2015)

Parameter	Value	Unit
Capex (540000m^3)	800	M€
Lifetime	20	years
Interest rate	5	%
Opex	9	% of capex
Scaling factor	0.7	

Similar to liquid hydrogen, the regasification plant was modelled after the Gate LNG terminal in Rotterdam. The Gate terminal has a capacity of 180000m^3 and an estimated cost of 800 M€(Quirijns, 2015). Table 217 shows the costs associated with the regasification of synthetic methane and final cost of shipping with regasification at Rotterdam.

Table 217: Estimated regasification costs for synthetic methane shipping

Capacity, tons	Capex, M€	Capex, M€/yr	Opex, M€/yr	Total costs, M€/yr
60100	323.9	26.0	29.1	55.1

Apart from the costs of synthetic methane produced in the Netherlands, import costs have to be added to the final system costs of synthetic methane transported by road or pipeline. Liquid transport would have an import price of 220 €/MWh while gaseous transport will have an import price of 220 €/MWh. Liquid storage costs have been previously estimated in section 8.6.2. The difference between the costs are in the range if few euro cents and therefore is not shown. This also indicates that the regasification process is not an expensive process.

8.6.4 Pipeline transport

As discussed in section 7.6.4, synthetic methane is transported through carbon steel pipes similar to natural gas. The transport of synthetic methane through pipeline involves multiple components other than the pipeline itself. Compressors are required to pressurise synthetic methane to its transport pressure and further give it enough kinetic energy to transport it along the pipeline. The compressors required for each transport route has already been modelled in the previous section and can be found in table 109. Table 218 shows the parameters used to estimate the cost of the compressors, and the pipeline as well. Since only the equipment costs for compressors were available, it was decided to use a factor of 1.9 to account for the other direct and indirect costs of the compressors as discussed in section 8.1. The compressor costs were based on a compressor station cost estimation by Willbros Engineering Inc. (Willbros Engineering Inc, 2005).

Table 218: Parameters used for calculating synthetic methane pipeline and compressor costs (Yang & Ogden, 2007)(Lensink & Pisca, 2019)(Parker, 2004)(Willbros Engineering Inc, 2005)

Parameter	**Value**	**Unit**
Lifetime of pipeline	50	years
Lifetime of compressor	20	years
Right of way	400000	€/km
Material cost multiplier	150	%
Compressor costs (5741 kW)	5.11	M€
Compressor scaling factor	0.9	
Opex	9	% of Capex
Electricity	0.07	€/kWh
Compressor Capex factor	190	% of compressor costs

The cost breakdown of the modelled compressors is shown in table 219. Another assumption that is made in this thesis, is that the decompressor at the end of the pipeline is assumed to be similar to the compressor at the beginning of the pipeline and thereby the costs are the same.

Table 219: Costs of compressors used for synthetic methane pipeline transport

Route	**Compressor size, kW**	**Compressor capex, M€**	**Electricity costs, M€/yr**	**Capex, M€/yr**	**Total cost, M€/yr**
Delfzijl - Emmen	7134	3.0	4.4	0.2	4.6
Delfzijl - Amsterdam	3535	1.6	2.2	0.1	2.3
Rotterdam - Amsterdam	47677	16.4	29.2	1.3	30.6
Rotterdam - Zeeland	63422	21.2	38.9	1.7	40.6
Rotterdam - Chemelot	46775 + 10167	20.2	34.9	1.6	36.5

Following the estimation of the compressor costs, the pipeline costs have to be estimated. The pipeline material costs have already been estimated in section 7.6.4 and the labour costs involved in laying the pipeline can be estimated using equation 23 without using the factor of 1.25. Table 220 shows the estimated costs of the pipeline for each transport route.

Table 220: Costs for transporting synthetic methane by pipelines

Route	**Material cost, M€**	**Labour cost, M€**	**Right of way, M€**	**Capex (including compressor), M€/yr**	**Opex (including compressor), M€/yr**	**Total cost, M€/yr**
Delfzijl - Emmen	0.2	6.1	24.3	2.2	12.0	14.2
Delfzijl - Amsterdam	0.6	17.4	70.4	5.1	12.6	17.7
Rotterdam - Amsterdam	0.7	6.6	23.8	4.3	64.2	68.6
Rotterdam - Zeeland	0.9	7.2	25.3	5.2	84.6	89.8
Rotterdam - Chemelot	2.0	18.8	68.6	8.1	81.5	89.7
€/MWh						5

Therefore, the estimated cost of transporting synthetic methane by pipelines is 5 €/MWh. The system costs will include the costs of production, imports with regasification, reforming and storage of synthetic methane. Following the same trend of the pipeline transport of the other energy carriers, the Opex dominates the pipeline transport costs.

8.6.5 Compressed road transport

As discussed in section 7.6.5, synthetic methane can be transported by road in its compressed form at a pressure of 250 bar. With the chosen tube trailer, 4.5 tons of synthetic methane can be transported in a single trip. The number of trips required by each tube trailer followed by the number of tube trailers required for each route and the compressor capacities were estimated in section 7.6.5. Therefore the cost of the tube trailers and the compressors can be estimated. The parameters used to estimate the costs of the tube trailers are listed in table 221 followed by the estimated costs of synthetic methane tube trailers shown in table 222. Other Opex refers to the maintenance, tyres and insurance of the tube trailers.

Table 221: Parameters used for estimating the costs of the tube trailers (Yang & Ogden, 2007)(Wulf & Zapp, 2018)(Botero, 2018)

Parameter	**Value**	**Unit**
Lifetime of tank containers	6	years
Capex of tube trailer	130000	€
Maintenance	6	% of Capex
Tires	4	% of Capex
Insurance	3	% of Capex
Driver wages	35	€/hr
Diesel	1.35	€/litre

Table 222: Estimated costs of synthetic methane tube trailers

Route	Driver wages, €/trip	Fuel costs, €/trip	Other Opex, €/tanker	Capex, M€	Opex, M€/yr	Capex, M€/yr	Total costs, M€/yr
Delfzijl - Emmen	280	66	16900	4.2	12.7	0.8	13.5
Delfijl - Amsterdam	455	192	16900	6.1	11.9	1.2	13.1
Rotterdam - Amsterdam	245	65	16900	27.4	75.1	5.4	80.5
Rotterdam - Zeeland	280	72	16900	36.5	113.0	7.2	120.2
Rotterdam - Chemelot	420	155	16900	40.3	135.3	7.9	143.2

The compressor capacities have already been modelled and can be found in table 113. The parameters used to estimate the costs of the compressors are listed in table 223. Similar to pipeline transport, a factor of 1.9 was used to estimate the Capex of the compressor.

Table 223: Parameters used for estimating the compressor costs for synthetic methane road transport (Willbros Engineering Inc, 2005)(Lensink & Pisca, 2019)

Parameter	Value	Unit
Compressor capacity	5746	kW
Compressor costs	5.1	M
Opex,	4	% of capex
Lifetime	20	years
Electricity costs	0.07	€/kWh
Compresseor Capex multiplier	190	% of compressor Capex

With the parameters known, the costs of the compressors were estimated and is shown in table 224. Similar to pipeline transport of synthetic methane, the unloading costs are assumed to be similar to the loading costs.

Table 224: Estimated costs of compressors required for synthetic methane road transport

Route	No. of pumps	Capex, M€	Opex, M€/yr	Electricity cost, M€/yr	Capex, M€/yr	Total costs, M€/yr
Delfzijl - Emmen	32	310.9	125.2	112.8	24.9	150.1
Rotterdam - Emmen	47	456.7	183.9	165.6	36.6	220.5
Rotterdam - Amsterdam	211	2050.2	825.5	743.4	164.5	990.0
Rotterdam - Zeeland	281	2730.4	1099.3	990.1	219.1	1318.4
Rotterdam - Chemelot	310	3012.1	1212.8	1092.3	241.7	1454.5

The total estimated costs of transporting synthetic methane by compressed tube trailers is estimated to be 153 €/MWh. Analysing the cost of the tube trailers and the compressors, the latter is the more dominant cost towards the transport costs. This could be a result of the high compressor capacities required for pressurising synthetic methane to the transport pressure of 250 bar from a storage pressure at atmospheric conditions.

8.6.6 Liquid road transport

As discussed in section 7.6.6, the system components involved in the transport of liquid synthetic methane by road vary with respect to compressed road transport, as liquefaction and regasification of synthetic methane is required at the source and destination, respectively. Also the imports do not have to be regasified, instead liquid synthetic methane storage will only be required at the port of Rotterdam. Regasification of the synthetic methane also includes storage. The first system component involved in the transport of liquid synthetic methane after production is the liquefaction plant. As discussed in section 7.2.8, Delfzijl and Rotterdam both have an excess of synthetic methane and thereby liquefaction plants would be required at both these locations. At the Rotterdam industrial cluster, the imports come in as a liquid and thereby does not need to be liquefied, leading to a lower capacity of the liquefaction plant at Rotterdam. The parameters used to estimate the costs of the liquefaction plants have been previously discussed, when estimating the costs of liquefaction plants for maritime transport of synthetic methane and thereby can be found in table 214. Table 225 shows the liquefaction costs estimated at the source.

Table 225: Liquefaction costs at Delfzijl and Rotterdam

Industrial cluster	**Plant size, ton/day**	**Capex, M€**	**Electricity cost, M€/yr**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Delzijl	793	1019.7	14.3	25.5	81.8	121.6
Rotterdam	11729	4735.3	210.9	118.4	380.0	709.2

Liquid synthetic methane is transported by specially built LNG road tankers. To estimate the cost for transporting liquid synthetic methane, the number of road tankers needed and the time taken for each trip have to be estimated, which has been done and is shown in section 7.6.6. The parameters used for calculating the cost of liquid synthetic methane transport is similar to that of compressed road transport, and thereby can be seen in table 221. The road tanker chosen for this thesis has a Capex of 448466€, including the cost of the prime mover (P.E & Fernandez, 2013)(Botero, 2018). Table 226 shows the costs of the transporting liquid synthetic methane by road.

Table 226: Estimated costs of road tankers for transporting liquid synthetic methane

Road routes	**Driver wages, €/trip**	**Fuel costs, €/trip**	**Other Opex, €/trailer**	**Capex, M€**	**Opex, M€/yr**	**Capex M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	700	66	58301	11.7	8.8	2.3	11.1
Delfzijl - Amsterdam	875	192	58301	5.8	5.8	1.1	7.0
Rotterdam - Amsterdam	665	65	58301	75.8	54.9	14.9	69.8
Rotterdam - Zeeland	700	72	58301	100.9	76.5	19.9	96.4
Rotterdam - Chemelot	840	155	58301	74.4	69.9	14.7	84.6

Liquid synthetic methane has to be regasified before it can be utilised at the destination. The regasification plants have been modelled in section 7.6.6 and the cost of the regasification plants is shown in table 227. The parameters used to estimate the costs are similar to that done for maritime transport and thereby can be seen in table 216.

Table 227: Regasification costs at the destination

Industrial cluster	**Capacity, tons/day**	**Capex, M€**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Emmen	424	10.1	0.9	0.8	1.7
Amsterdam	3044	40.1	3.6	3.2	6.8
Zeeland	3769	38.2	3.4	3.1	6.5
Chemelot	2780	46.6	4.2	3.7	7.9

The pumps to load and unload liquid synthetic methane from and onto the road tankers are the final system component for which the costs have to be estimated. The pump capacities have been modelled in section 7.6.6 and is shown in table 117. The parameters used to estimate the cost of the pumps can be seen in table 228 followed by the estimated costs of pumps shown in table 229.

Table 228: Parameters used for estimating the costs of liquid synthetic methane pumps (Loh et al., 2002)(Lensink & Pisca, 2019)

Parameter	**Value**	**Unit**
Pump size	65	kW
Capex	1884	/kW
Opex,	4	% of Capex
Lifetime	20	years
Electricity costs	0.07	€/kWh
Pump Capex factor	190	% of pump Capex

Table 229: Estimated costs of liquid synthetic methane pumps

Route	**No. of pumps**	**Capex, M€**	**Electricity costs, M€/yr**	**Opex, M€/yr**	**Capex, M€/yr**	**Total costs, M€/yr**
Delfzijl - Emmen	26	4.9	1.0	1.2	0.4	1.6
Delfzijl - Amsterdam	13	2.4	0.5	0.6	0.2	0.8
Rotterdam - Amsterdam	169	31.7	6.7	8.0	2.5	10.5
Rotterdam - Zeeland	225	42.2	9.0	10.7	3.4	14.0
Rotterdam - Chemelot	166	31.1	6.6	7.9	2.5	10.4

Therefore the cost of transporting liquid synthetic methane by road which includes; liquefaction at the source, loading the liquid synthetic methane, transporting it using LNG road tankers, unloading the liquid synthetic methane from the tankers and regasification at the destination was estimated to be 21 €/MWh.

8.6.7 System costs of synthetic methane transport

The system costs of synthetic methane for pipeline and road transport was estimated and is shown in table 230.

Table 230: Estimated system costs of synthetic methane transport

Transport medium	**Production, €/MWh**	**Storage, €/MWh**	**Transport medium, €/MWh**	**Reforming, €/MWh**	**Import, €/MWh**	**System costs, €/MWh**
Pipeline	250	4	5	36	220	273
Compressed road	250	4	153	36	220	422
Liquid road	250	2	21	36	220	288

Pipeline transport is the most economical mode of transport followed by liquid road transport and compressed road transport. Compressed road transport has a very high estimated cost due to the dominance of transport costs, which is not the case for pipeline and liquid road transport. As seen in the earlier sub-section, the loading and unloading costs dominates in the transport medium costs for compressed road transport.

9 Region specific costs

This chapter will estimate the cost of the hydrogen delivered to the six industrial clusters.

9.1 Cost at each industrial cluster

The system costs that have been estimated for transporting the energy carriers was for the Netherlands as a country and not specific to any industrial cluster. As discussed previously, production of hydrogen is expected only at four out of the six industrial clusters while imports are assumed to only come in to the port of Rotterdam. Therefore, the cost of the energy carrier at each industrial cluster is expected to have a different price. From section 8, it can be inferred that hydrogen pipelines would be the most economic energy carrier and transport mode for transporting hydrogen across the Netherlands. Therefore, the region specific costs was estimated based on hydrogen pipeline transport.

To be able to distribute the costs among the industrial clusters, it was important to look at the system boundaries again, which is shown in figure 10. The costs of the system components at the source are to be shared among the industrial clusters, while the transport costs are allocated to the clusters receiving the hydrogen and the costs of storage at the destination has to be borne by the same clusters. The system components at the source refer to the production, import and storage components. The reason as to why the costs have to be shared are due to the fact that the imports that come to the Port of Rotterdam is consumed at Rotterdam and also further distributed to Amsterdam, Zeeland and Chemelot. This also applies to the production at Delfzijl and the storage costs at the source. Table 231 shows the demand of the industrial clusters and how the production and imports are distributed among the industrial clusters. Negative values indicate an excess of the energy carrier at that location.

Table 231: Distribution of the production and imports among the industrial clusters

Industrial cluster	**Demand, ktons/yr**	**Production, ktons/yr**	**Import through Rotterdam, ktons/yr**	**Production from Delfzijl, ktons/yr**
Delfzijl	47	208	-	-162
Rotterdam	1130	652	478	-
Zeeland	708	220	488	-
Emmen	33	-	-	33
Chemelot	434	-	434	-
Amsterdam	802	602	72	128
Total	3155			

An assumption made here, is that the production of hydrogen is first consumed on site and the remainder if any, is transported to the other clusters. As seen in table 231, Delfzijl only consumes 47 ktons of hydrogen and has an excess of 162 ktons, which is further transported to Emmen and Amsterdam. The same happens for the imports, Rotterdam utilises 478 ktons of the imports while the rest is transported to Zeeland, Chemelot and Amsterdam. Eventhough, Emmen does not have production, it still has to pay for storage at Delfzijl and the same applies to Amsterdam. For the case of imports, Amsterdam, Zeeland and Chemelot have to pay for the storage of the imports at Rotterdam. Since the costs of the individual components are known as well as the demand at each industrial cluster, the costs incurred by each industrial cluster can be estimated. The costs per system component for each industrial cluster is shown in table 232.

Table 232: Individual system component cost at each industrial cluster

Industrial cluster	**Production, M€/yr**	**Import, M€/yr**	**Storage at source, M€/yr**	**Transport, M€/yr**	**Storage at destination, M€/yr**	**Total costs, M€/yr**
Delfzijl	282	-	7	-	-	289
Rotterdam	3931	2322	100	-	-	6353
Amsterdam	4403	351	112	22	31	4919
Zeeland	1328	2372	34	13	75	3822
Chemelot	-	2110	-	26	67	2203
Emmen	202	-	5	5	5	217

The production cost seen at the Emmen industrial cluster is the costs of its share of production at Delfzijl, and Amsterdam's share of cost of production at Delfzijl is also included in the production costs at Amsterdam. The storage and regasification costs associated to the imports are added to the costs of the imports as well. The final costs of hydrogen at each industrial cluster is estimated by dividing the total costs incurred at the cluster by the demand for hydrogen at the cluster. This is projected in figure 26.

Figure 26: Cost of hydrogen at each industrial cluster transported by pipeline (system cost - 151 €/MWh)

As seen in figure 26, the cost of hydrogen varies across the six industrial clusters in the Netherlands. The estimated cost for hydrogen pipeline transport for the Netherlands was 151 €/MWh. Therefore a clear difference can be noticed between region specific costs and country costs for the energy carrier. This could be a result of the difference in the quantity of hydrogen transported, consumed and stored at the six industrial clusters. The difference in costs will be further discussed in chapter 10.

10 Discussion

This chapter will start off with an overview of the results, further analysing in depth in each subsection followed by a system level discussion. The chapter ends with a discussion on the limitations of this thesis.

10.1 Summary of results

Having estimated the energy efficiency and the system costs of each energy carrier in the different transport modes, the results were consolidated and analysed. Table 233 shows both the system costs and the energy efficiencies of the transport systems for all the energy carriers. Eff refers to the efficiencies of the different systems.

Table 233: System costs and energy efficiencies of the transport systems

	Pipeline		**Liquid road**		**Compressed road**		
	Cost, €/MWh	**Eff, %**	**Cost, €/MWh**	**Eff, %**	**Type**	**Cost, €/MWh**	**Eff, %**
Hydrogen	151	52	175	51	250 bar	246	45
					350 bar	260	44
					500 bar	284	42
Ammonia	211	36	217	36	-	-	-
Methanol	216	37	218	37	-	-	-
DME	215	26	220	26	-	-	-
Synthetic methane	273	28	289	28	250 bar	422	23

As seen in table 233, the cost of the energy carriers vary from 151 - 422 €/MWh depending on the mode of transport used. The benchmark for a renewable energy carrier would be to compare it with an existing energy carrier that is transported across a country. In the case of the Netherlands, natural gas is the most consumed energy carrier with a large network across the Netherlands followed by crude oil and coal (CBS, 2017). The cost of natural gas sold to industries as of 2018 varies from 26 - 38 €/MWh depending on the amount of natural gas consumed (Statista, 2018). In comparison, the energy carriers assessed in this thesis are at least five times more costly than natural gas currently sold to industries. This shows that currently none of these energy carriers are cost competitive, making it difficult to consider any of these energy carriers as a replacement for natural gas right now. Nevertheless, this thesis envisions a timeline of 2050 for the large-scale implementation of a low-carbon scenario. By 2050, it is expected that the costs affecting the production, transport, storage and reforming of the energy carriers to decrease through technological advances and mass production of technology required at each step of the supply chain. Analysing the costs and efficiencies listed in table 233, it can be inferred that hydrogen pipelines have the highest efficiency and the lowest system costs making it the most efficient and economical transport mode and energy carrier. To analyse the efficiencies and system costs in detail, this table was further broken down and discussed in the sections that follow.

10.2 Energy efficiency

This thesis assumes that everything, from the production to the storage at the destination will be powered by renewable energy. Therefore, it is worth investigating how much of energy was consumed for transporting each energy carrier, which is shown in figure 27.

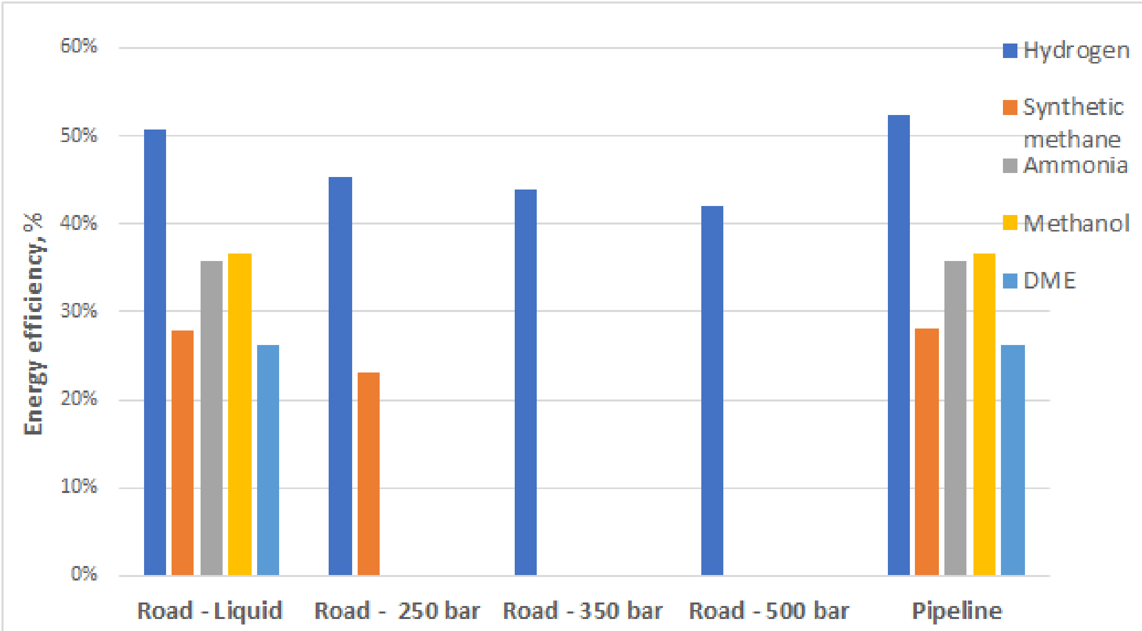

Figure 27: Energy efficiencies of the energy carrier using the three transport modes

It is clear that hydrogen in all forms of transport is the more efficient energy carrier to be transported followed by methanol and ammonia. This result was expected as hydrogen production, an intensive energy consumption process with an efficiency of 66%, serves as the starting point for the production of the other energy carriers. The production of the other four energy carriers incorporate more conversion steps after hydrogen production, which results in lower efficiencies compared to hydrogen. Therefore the electrolyser efficiency is very important in the renewable production of the energy carriers, as an improvement in the efficiency will have a big impact in the final efficiency of the system. Hydrogen pipelines was found to be the most energy efficient transport mode followed closely by liquid hydrogen road transport. The difference in efficiencies was a result of the need to liquefy and regasify hydrogen for liquid road transport which is more energy demanding compared to compressing hydrogen for pipeline transport. On the other hand, compressed hydrogen road transport has a lower energy efficiency compared to both pipeline and liquid road transport. This is attributed to the high energy consumption of the compressors for loading and unloading due to the high transport pressures for compressed road transport which vary from 250 - 500 bar, in contrast to the pipeline pressure of 35 bar and liquid road transport pressure of 1 bar.

Methanol has the second highest efficiency followed closely by ammonia in third as both energy carriers require a relatively low amount of energy for production compared to synthetic methane and DME. Most of the energy consumed for the production of methanol and ammonia is for the hydrogen electrolyser for hydrogen production which can be seen in section 7.4 and 7.3 for methanol and ammonia respectively. The losses associated with methanol throughout the supply chain is relatively low compared to ammonia, as methanol is transported and stored as a liquid at room temperature while ammonia has to be cooled to -33°C to be transported. Cooling ammonia consumes more energy while making ammonia prone to boil-off losses during storage and transport especially shipping. DME is the least efficient energy carrier at 26% followed by synthetic methane at 28%. DME is a derivative of methanol and therefore is expected to have a lower production efficiency than methanol. Since the production of the energy carrier is the most energy intensive part of the system, the efficiency of the production process has a major impact on the final system efficiency.

In the case of synthetic methane, the production of synthetic methane is a relatively energy intensive process compared to the other energy carriers resulting in a lower final system efficiency. Not many papers in recent years have made a comparison of energy efficiencies of the transport of the energy carriers researched into in this thesis. Adamson et.al compared methanol and hydrogen to petrol as an alternative transportation fuel, concluding that hydrogen would have a higher efficiency by a small margin over methanol but Sprecht et.al did a similar analysis but concluded that the methanol blend (M85) is more efficient than liquid hydrogen (Adamson & Pearson, 2000)(Specht, Staiss, Bandi, & Weimer, 1998). Since both authors have performed this assessment almost 20 years ago based on the technology available at that time, a comparison of the results from this thesis to that of the authors could not be made.

In general, pipeline transport and liquid road transport have almost similar efficiencies across all energy carriers. As seen in the relevant sub-sections in chapter 7, the energy consumed by the transport medium in pipeline and liquid road transport is low compared to the production and import of the energy carriers. This was a result of the high energy demand for the production of the energy carrier. In contrast to pipeline and liquid road transport, the transport medium in compressed road transport has a more significant energy consumption. This is attributed to the high transport pressures required for compressed road transport, which in turn requires larger compressor capacities resulting in a higher energy consumption. It has to be noted that this system does not account for the efficiency of the DAC systems used for carbon capture from the atmosphere as in this thesis, it is assumed that CO_2 is bought. Therefore the efficiency of methanol, synthetic methane and DME is expected to decrease even further.

10.3 System cost breakdown

Figure 28 shows the system costs in €/MWh of the energy carriers in the different transport modes. Also can be seen is the distribution of the system costs among the five major system components: production, storage, transport, imports and reforming. Storage costs include the costs of storage both at the source and destination while transport costs include loading, transport and unloading. In the case of hydrogen and synthetic methane liquid road transport, liquefaction and regasification costs are included in the transport medium costs as well.

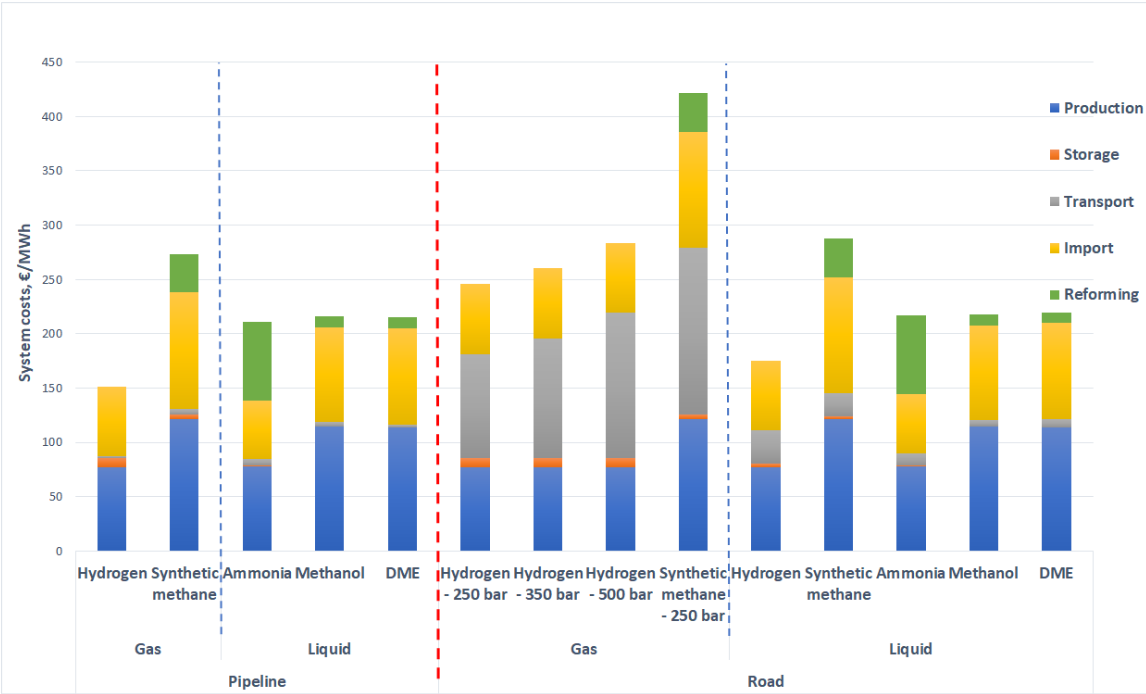

Figure 28: System costs breakdown

Figure 28 is a consolidated stacked bar chart which shows the effect that each of the five components have towards the system costs. The components that have a major effect will be further analysed in the sections that follow. In general from figure 28, it is clearly visible that production and import costs dominate while transport and storage costs are almost negligible in the case of pipeline and liquid road transport. This is not the case for compressed road transport, in which the cost of the transport medium is much more significant. This difference in magnitude of transport costs was a result of the high transport pressures required for compressed road transport, compared to pipeline and liquid road transport. To explain what causes these costs to dominate, the transport costs, production costs and import costs will have to be analysed in more detail, which is done in section 10.4, 10.5 and 10.6. The costs of reforming represents the reforming of the energy carriers to produce hydrogen, to satisfy the demand of 96 PJ of hydrogen needed for non-energy uses. Except for ammonia, the reforming costs do not have a large effect on the system costs, which could be a result of smaller reformers required to only produce 96 PJ of hydrogen relative to the demand of 444 PJ of hydrogen needed across the Netherlands. In the case of ammonia, the reforming costs form a large part of the system costs which indicates that either ammonia is a difficult molecule to reform/break-up or not much research and implementation has been done in this area to bring down the costs of ammonia reforming. Taking a system level perspective, hydrogen pipeline transport is clearly the most economical mode of transporting hydrogen followed closely by liquid hydrogen road transport and then ammonia pipeline transport. This was clearly a result of the low production, import and transport costs, relative to the other energy carriers and transport modes. In all modes of transportation, synthetic methane has the highest costs as a result of high production costs. To understand in detail what factors affect these costs, these observations will also be further discussed in detail in the coming sections.

10.4 Transport costs

As seen in figure 28, there was a significant variation in transport costs for pipeline and liquid road transport when compared to compressed road transport. To analyse and explain this in more detail, figure 29 was produced. Figure 29 presents a comparison of the transport costs of all the energy carriers in the different transport modes.

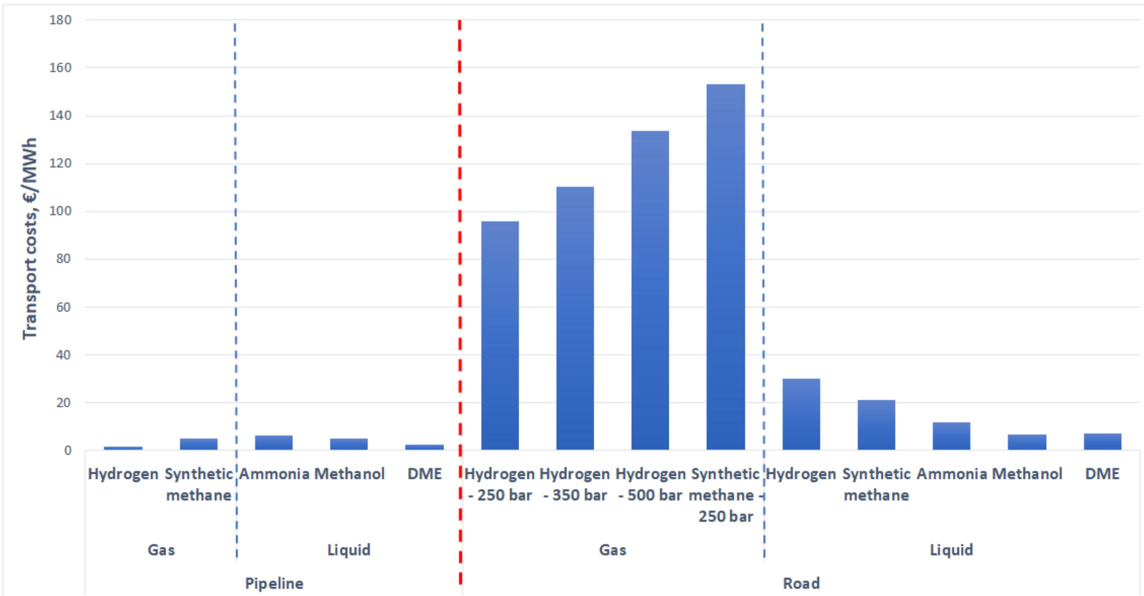

Figure 29: Transport costs

At first glance, the difference between the costs of pipeline and road transport are significant, resulting in the cost of pipeline transport to almost not be visible in the bar chart above. Therefore, this bar chart will have to be segregated within the different transport modes and analysed further, which can be found in section 10.4.1 and 10.4.2. In general, pipeline transport is clearly the most economic transport mode across all the energy carriers with transport costs below 6 €/MWh. This could be a result of the longer lifetime of pipelines relative to road transport. Following pipeline, liquid road transport of methanol, DME and ammonia also have relatively low transport costs. Liquid hydrogen and liquid synthetic methane road transport have relatively higher costs, which could be attributed to the fact that they have to be liquefied at the source and regasified at the destination, making them more costly to transport. Compressed synthetic methane road transport has the highest transport cost followed by compressed hydrogen at 500 bar, 350 bar and 250 bar in that order. This indicates that the transport costs increases as higher pressure tube trailers are used. To further analyse and justify the observations made, transport costs of the energy carriers in a specific transport mode will be analysed in more detail in the sub-sections that follow,

10.4.1 Pipeline transport

To identify what factors affect the cost of pipeline transport, a stacked bar graph with the breakdown of the costs was produced which can be seen in figure 30. ROW is known as right of way, which refers to the purchase of land for building the pipeline on. Compressor/pump refer to the Capex of the compressor and pump used.

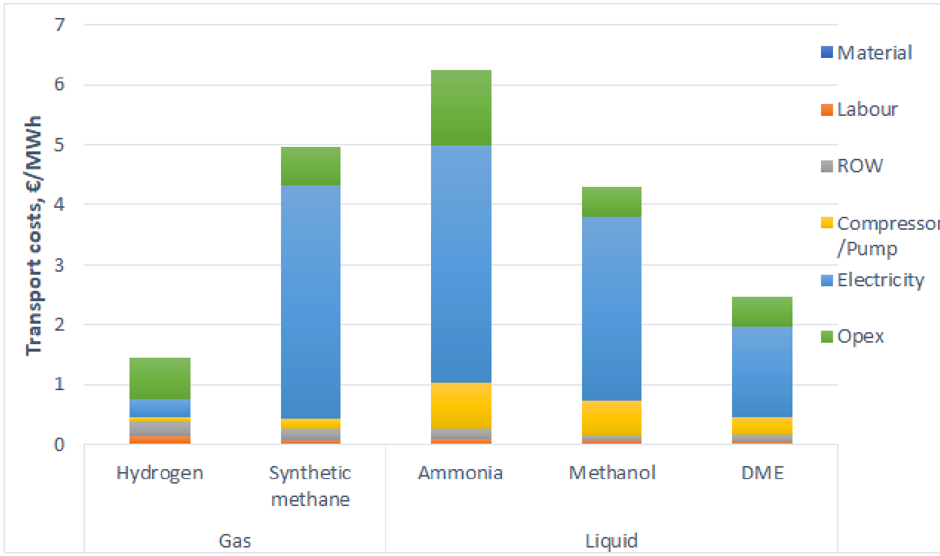

Figure 30: Pipeline cost breakdown

The costs of electricity to operate the compressors and pumps dominated the transport costs for all the energy carriers followed by the Opex, and the Capex of the compressor and pump. Another observation from the graph, is that the costs for hydrogen pipelines is relatively low compared to the other energy carriers. This can be attributed to the fact that hydrogen is produced at a pressure of 3MPa and therefore is stored at the same pressure, before transport. This was not the case for the other energy carriers as they are stored at atmospheric pressure, which results in higher compression ratios required and therefore large compressor capacities. Also, the quantity of the other energy carriers that have to be transported is also relatively higher than that for hydrogen. Therefore, pipelines were relatively smaller and compression costs lower in the case of hydrogen transport. This also explains why DME pipeline costs were lower than methanol despite being derived from methanol, as a smaller quantity of DME had to be transported compared to methanol. DME has 6 hydrogen molecules in its structure compared to methanol that has 4 molecules, and thereby requires a smaller amount to satisfy the hydrogen demand.

To verify the costs of the pipeline transport of the energy carrier in this thesis, the results have to be compared to results of other reports/literature. The future of Hydrogen report by the IEA estimated the costs of transporting hydrogen and ammonia by pipeline including the costs of storage (IEA, 2019). The estimated cost of transporting hydrogen by pipeline for a distance of 1500 km including storage was 1 $/kgH_2$, for a throughput of 340 ktonH$_2$/yr (IEA, 2019). This thesis considers a network of pipelines across the Netherlands of approximately 530 km with a throughput of 1200 ktonsH$_2$/yr, therefore comparing the costs estimated by IEA to the cost estimated in this thesis was not possible. The distance considered by IEA is triple while the throughput is $\frac{1}{4}$th of that considered in this thesis. Therefore, the material, labour and ROW costs are expected to increase while the compressor/pump costs may increase due to a longer distance but may also decrease due to a lower throughput. Despite this, in the same report, the cost of transporting hydrogen by pipeline including storage was plotted for a varying distance on a line chart. Estimating from the graph, hydrogen could be transported by a 500 km pipeline at approximately 0.25 \$/kgH$_2$ including storage costs (IEA, 2019). 0.25 \$/kgH$_2$ converts to 0.22 €/kgH$_2$ using a conversion rate of 1\$ to 0.89€. When storage costs are added to the pipeline transport costs of hydrogen in this thesis, a combined cost of 0.21 €/kgH$_2$ (5.35 €/MWh) was estimated. Comparing both these costs, the estimates seem to be in agreement with each other. Further the report also estimates the cost of ammonia pipeline transport, which has been plotted in the same line chart. At a range of 500 km, ammonia pipeline transport with storage is more economical than hydrogen and was estimated to be around 0.22 \$/kgH_2 or 0.20 €/kgH_2. This thesis estimated ammonia pipeline and storage costs to be 0.22 €/kgH_2 (6.4 €/MWh), which is slightly higher than the estimate from IEA. This could be attributed to the higher inlet pressure of 10 MPa used in this thesis compared to 8 MPa used by the IEA in their report (IEA, 2019). From this comparison, it can be worth noting that just analysing the pipeline costs would have indicated that hydrogen pipelines are more economical than ammonia but the case does not hold true when storage costs are added. Adding storage costs to the pipeline cost results in ammonia and hydrogen having similar costs. There were not many papers in recent times to validate the costs of synthetic methane, methanol and DME pipelines.

In countries like the Netherlands which have an extensive natural gas pipeline infrastructure, it is possible to either directly use or retrofit these pipelines to transport the energy carriers. As seen in figure 30, using the existing network directly or retrofitting the pipelines may reduce the compressor/pump Capex, material costs, labour costs and right of way expenses but that does not influence the transport costs as much, as the contribution of these three factors towards the system costs is relatively lower compared to electricity costs and pipeline Opex. It is visible from figure 30, that operating the pipeline is the most expensive part of pipeline transport relative to building the pipeline infrastructure or purchasing the land to build the infrastructure on. To confirm this, a sensitivity analysis is done for the pipeline transport of the energy carriers by reducing the material costs, labour costs, ROW and compressor/pump Capex in steps of 25% to zero, while keeping the cost of electricity and Opex constant.

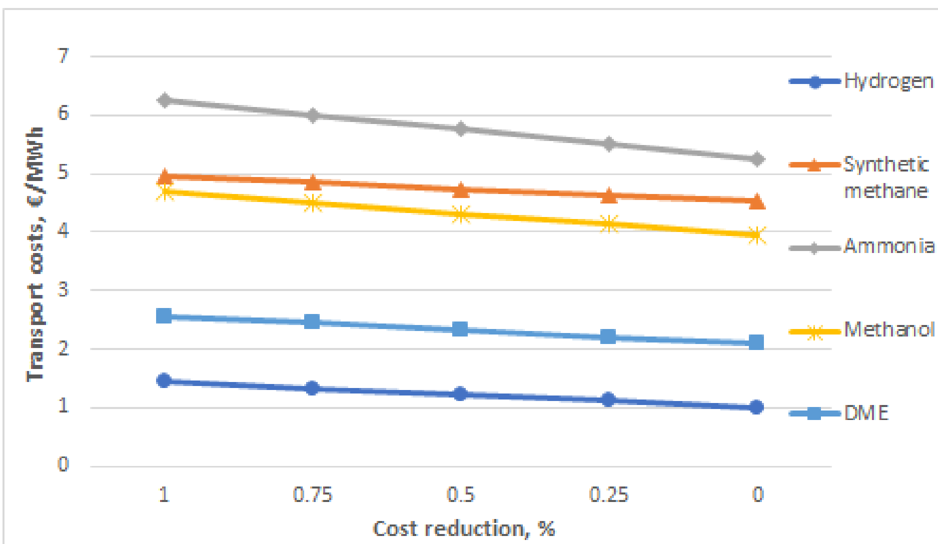

Figure 31: Sensitivity analysis on the Capex of the pipeline

As seen in figure 31, there is a reduction of at most 1 €/MWh across the energy carriers. For synthetic methane, ammonia and methanol, this reduction will not have a large impact but in the case of hydrogen and DME, this reduction could have an impact as the transport costs are low in the base case. When considering the system costs, this reduction will go unnoticed as the pipeline transport costs are negligible when compared to production and import costs. It has to also be noted that labour costs reduced here accounts for the costs incurred when building the pipeline and not for operating the pipeline.

10.4.2 Road transport

From figure 29, it can be inferred that liquid road transport is more economical compared to compressed gas road transport. This is evident in both cases of hydrogen and synthetic methane road transport. To investigate further the factors influencing the difference in costs, a stacked bar chart seen in figure 32 and 33 was produced. Truck in both the bar graphs represent only the Capex of the truck/transport vehicle.

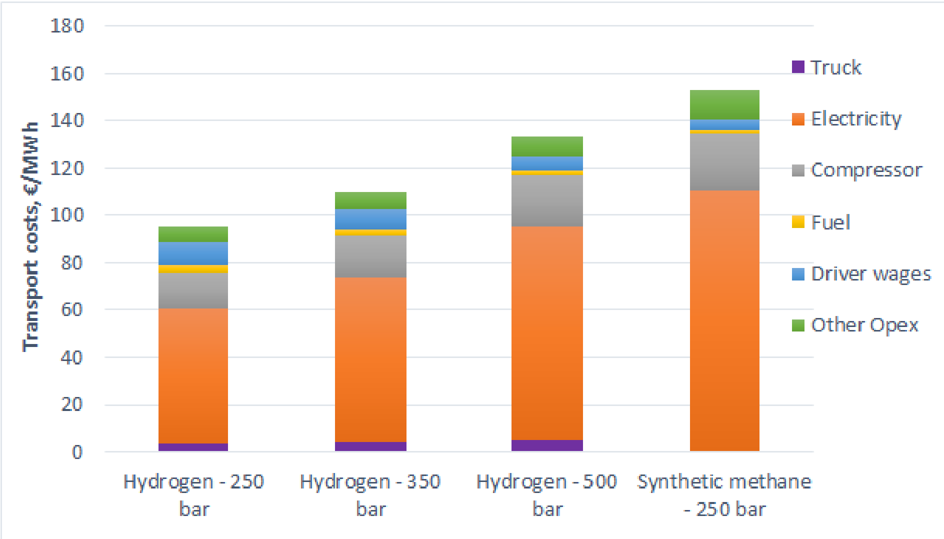

Figure 32: Compressed road transport cost breakdown

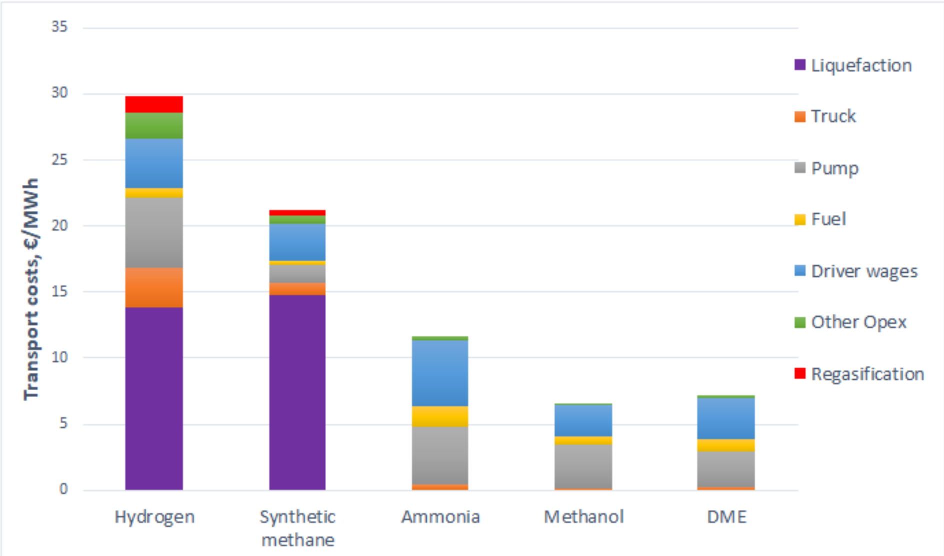

Figure 33: Liquid road transport cost breakdown

Similar to pipeline transport, from figure 32, the electricity costs to operate the compressors dominate in compressed gas road transport followed by the compressor Capex. This gives a good indication as to why compressing to higher pressures may not necessarily be the best option even if at higher pressures, higher volumes of gas can be transported in a single trip. Higher pressures would require higher compressor capacities increasing the Capex of the compressor and the electricity costs which as seen in figure 32 will not be compensated by the costs avoided by using less number of trucks. It also has to be taken into account, even if the Capex of the trucks do not contribute much to the final transport costs, the difference in Capex between a 250 bar hydrogen tube trailer and 500 bar hydrogen tube trailer is currently almost half a million euros. Analysing liquid road transport, hydrogen and synthetic methane have higher costs due to the additional costs of liquefaction and regasification. For ammonia, methanol and DME, the costs are dominated by the loading and unloading costs using pumps and wages paid to the drivers. Another observation is that the Capex of the trucks are dominant in the case of hydrogen and synthetic methane. This could be attributed to the fact that even after being liquefied, to reduce the volume occupied by the gas, more number of trucks are needed for both energy carriers relative to ammonia, methanol and DME. For liquid hydrogen or liquid synthetic methane to be competitive with the other three energy carriers, the cost of liquefaction will have to reduce significantly.

10.5 Production costs

As seen in figure 28, production costs dominated the system costs of transporting the energy carrier. Therefore, figure 34 was produced to analyse the factors that affect the cost of production of the energy carriers.

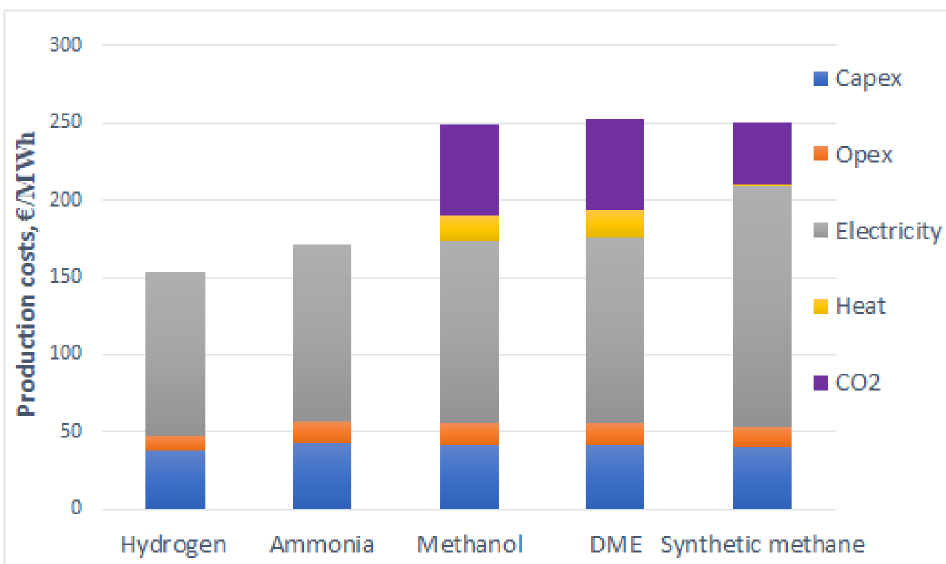

Figure 34: Production costs breakdown

As seen in figure 34, the cost of electricity forms the largest part of the production costs followed by the Capex, and the CO_2 costs in the case of methanol, DME and synthetic methane. Since hydrogen production serves as the staring point for the production of all the energy carriers analysed, it can be inferred from figure 34 that hydrogen production contributes to more than half of the costs for the production of the energy carriers. Therefore, it is worth analysing whether hydrogen production costs are in line with other literature. Navigant reports that current (2018) costs of green hydrogen[7] varies from 90 - 210 €/MWh with a mean of 150 €/MWh (Navigant, 2019). The mean production cost of 150 €/MWh is inline with the costs estimated in this thesis of 153 €/MWh, but the large variation in costs shows the uncertainties in the costs calculated or estimated in different reports/literature. Since the hydrogen economy in itself is a scenario for the future, it is important to analyse how the hydrogen production costs maybe affected by technical advancements or lower electricity costs. From figure 34, electricity and the Capex of the electrolyser account for more than 90% of the final hydrogen production costs. If both these factors are to decrease in the future, a very steep cost reduction can be experienced. To realise the varying costs of hydrogen, a sensitivity analysis is performed based on the varying cost of electricity, which is expected to reduce due to the large-scale integration of renewable energy systems.

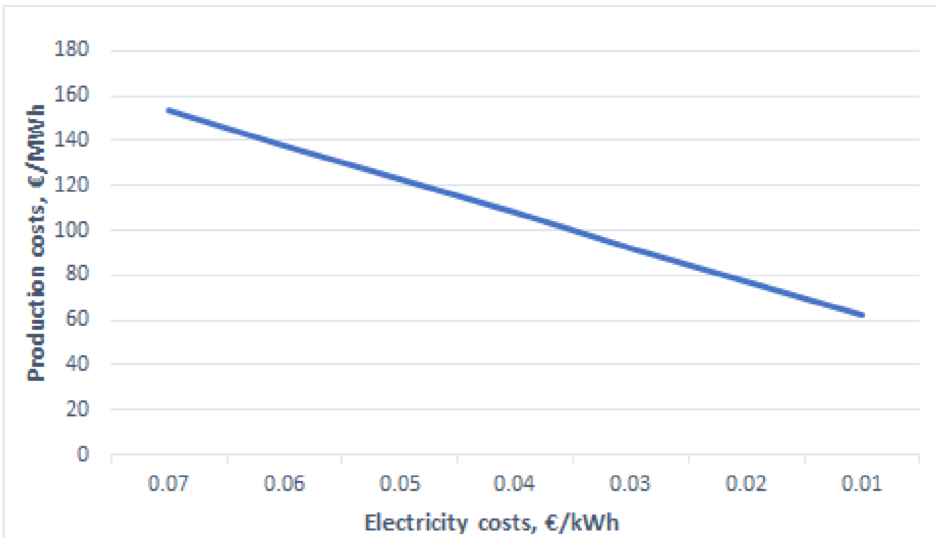

Figure 35: Hydrogen production costs with varying electricity costs

As seen in figure 35, hydrogen production costs almost reach 60 €/MWh at an electricity cost of 0.01 €/kWh. Navigant estimates electricity from the North Sea offshore wind farms to have a cost varying between 0.03 - 0.04 €/kWh by 2050 (Navigant, 2019). From figure 35, at a cost of electricity of 0.03 €/kWh, hydrogen production is estimated to have a cost around 95 €/MWh. Since it is also expected that the Capex of the electrolyser would reduce in the future, another sensitivity analysis was performed keeping the cost of electricity constant at 0.03 €/kWh while varying the Capex of the electrolyser in steps of 200 €/kW from the current Capex of 1100 €/kW.

[7] Green hydrogen is hydrogen produced from electricity generated by renewable sources

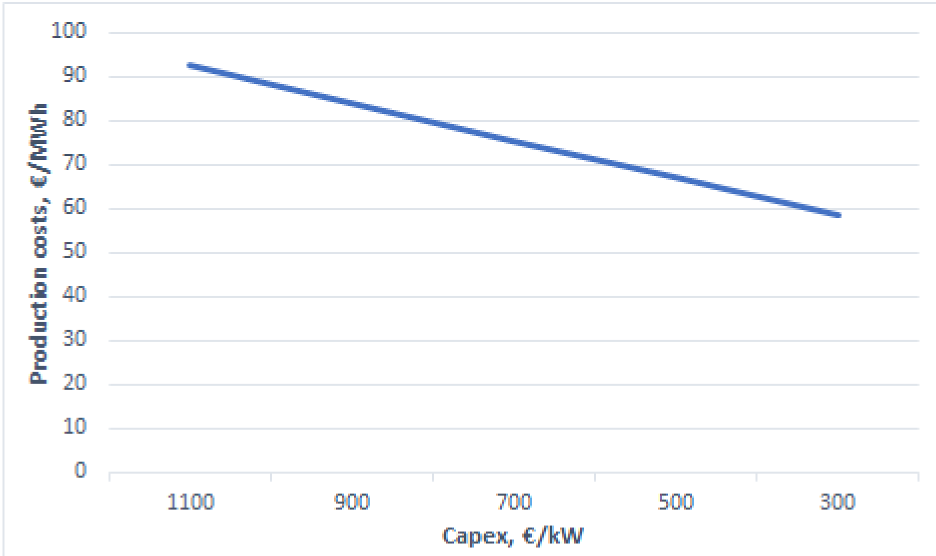

Figure 36: Hydrogen production costs with varying electrolyser Capex

From figure 36, hydrogen can be produced at a cost of approximately 60 €/MWh, with an electrolyser Capex of 300 €/kW and an electricity cost of 0.03 €/kWh. It is also worth noting that the hydrogen production cost is more sensitive to the cost of electricity than the Capex of the electrolyser, which can be seen in the steepness of the line or the change in production costs as seen in figure 35 and 36. Navigant estimates a hydrogen production cost between 48 - 61 €/MWh with a electrolyser Capex of 420 €/kW (Navigant, 2019). Assuming an electrolyser Capex of 420 €/kW, this thesis estimates a hydrogen production cost of 63 €/MWh using a higher heating value for hydrogen. Since Navigant uses the lower heating value to estimate the production costs, to compare costs, the hydrogen production costs estimated in this thesis using the lower heating value for hydrogen is 75 €/MWh. This cost is relatively higher compared to Navigant's estimate but could be justified with the different assumptions taken into account. This thesis assumes a depreciation period of 20 years with a stack replacement every 10 years while Navigant assumes a depreciation period of 30 years (Navigant, 2019). Similarly an Opex of 3% of the Capex and a system efficiency of 80% is assumed by Navigant while this thesis assumes an Opex of 4% of the Capex and an electrolyser efficiency of 66% (Navigant, 2019). The future of hydrogen report by IEA has also estimated hydrogen production costs in Europe to be around 4.90 $/kgH_2$ by 2030, with a maximum price of 6.50 $/kgH_2$ which converts to 5.80 €/kgH$_2$[8] (IEA, 2019). In comparison to this, the estimated hydrogen production cost in this thesis of 6.03 €/kgH$_2$ (153 €/MWh) is also on the higher end. The higher costs estimated in this thesis could be justified based on the high cost electricity of 70 €/MWh and the Capex of the electrolyser of 1100 €/kW used in this thesis. The IEA reports mentions that the price of electricity would further decrease in the future without indicating what the expected prices would be but states that the Capex of the electrolyser is expected to reduce to 450 - 500 €/kW by 2030 (IEA, 2019).

Hydrogen production is still just one step in the production of the other energy carriers and other factors like CO_2 costs are expected to also have an impact on the final production costs of the energy carriers. In this thesis, CO_2 has been assumed to be extracted from the atmosphere using Direct Air Capture (DAC) systems at a cost of 222 €/tonCO_2 (Fasihi et al., 2019). M.Fasihi et.al, estimates that the price of low temperature DAC systems can further drop to 38 €/tonCO_2 by 2050, with

[8] A currency conversion of 1$ to 0.89 € was used

a steep learning curve, and mass production and commercialization of DAC systems (Fasihi et al., 2019). Even if the costs of CO_2 reduces by a large margin, it is visible from figure 34 to conclude that the production of ammonia is still more economical than the other three energy carriers. A combination of a reduction in costs of electricity and CO_2 would be able to push the production costs of methanol, DME and synthetic methane below that of ammonia. For testing this hypothesis, a sensitivity analysis is done by reducing the costs of CO_2 in steps till 38 €/tonCO_2 while keep the cost of electricity fixed at 35 €/MWh. This has been plotted and shown in figure 37.

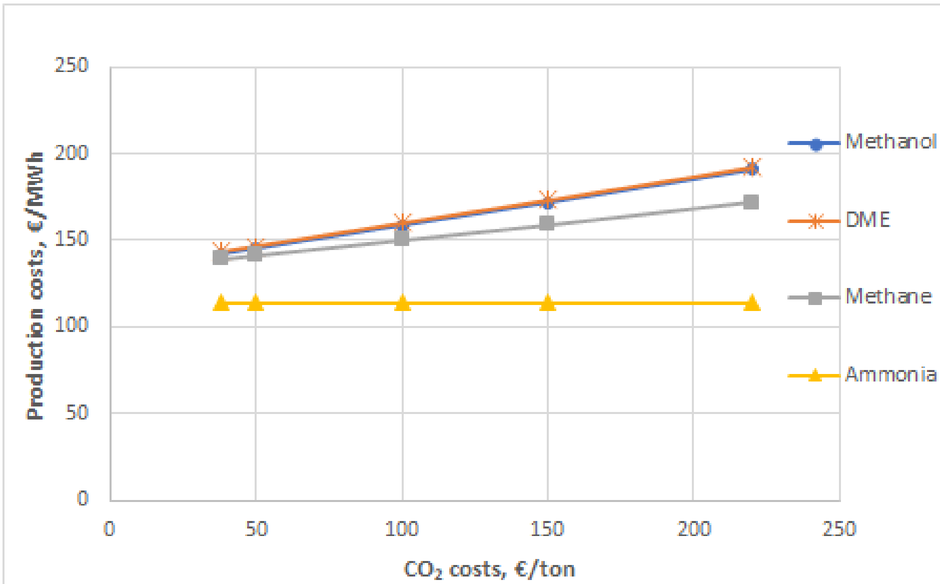

Figure 37: Production costs with varying CO_2 costs

From figure 37, it is clearly visible that even at the point where CO_2 reaches 38 €/tonCO_2, all three energy carriers still have higher production costs compared to ammonia. The cost of ammonia does not change as the CO_2 prices changes, as it is does not require CO_2 for production. An interesting observation from figure 37, is that the cost of methanol and DME production reduces faster than that of synthetic methane. This indicates that methanol and DME are more sensitive to the cost of CO_2 relative to synthetic methane. Thereby for low CO_2 costs, methanol and DME is expected to be more economical to produce compared to synthetic methane.

10.6 Import costs

The import costs include the cost of the energy carrier sold at the port of source, the shipping costs and the storage costs at the port of Rotterdam. In the case of hydrogen and synthetic methane, liquefaction and regasification costs are also included. The shipping costs constitutes of multiple factors which can be seen in chapter 8 in the relevant sections. Figure 38 shows the breakdown of the costs for imports.

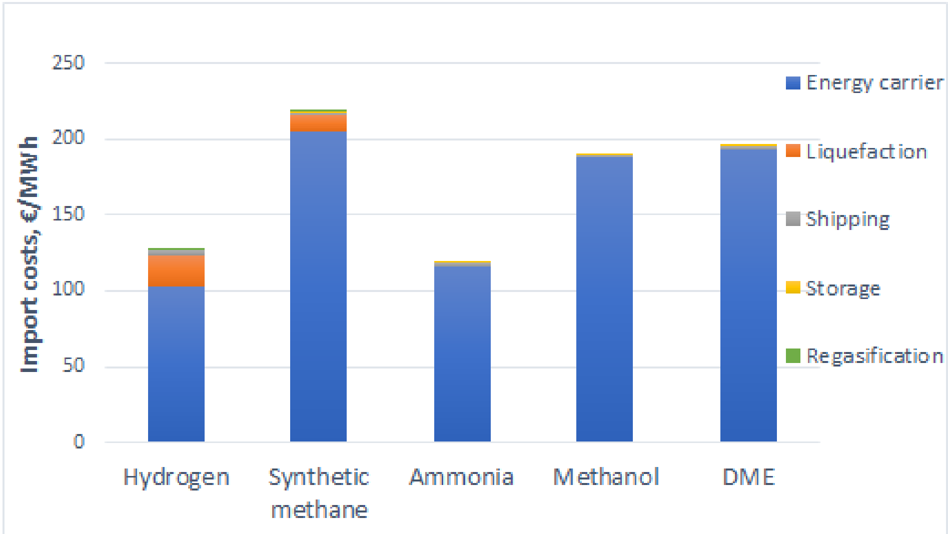

Figure 38: Import costs breakdown

From figure 38, it is clear that the selling price of the energy carriers at the port of source outweighs the rest of the costs by a large margin. This is consistent with transportation of the energy carriers by pipeline and road transport on land, in which production costs dominate as well. Storage, transport and regasification have an almost negligible contribution to the final costs while liquefaction has a visible contribution but is relatively low compared to the cost of the energy carrier. An important observation from figure 38 is that the import costs of ammonia is lower than that of liquid hydrogen despite hydrogen being used to produce ammonia. This observation is in agreement with the future of hydrogen report that estimates the same (IEA, 2019). This could be attributed to the fact that liquefaction of hydrogen increases the costs further and handling cryogenic liquid hydrogen is more expensive than liquid ammonia at -33°C. Amongst all the energy carriers, synthetic methane has the highest costs as a result of high production costs and also the need to liquefy synthetic methane before transporting it by ship.

The cost of the energy carrier will depend on the country/region where the energy carrier is sourced from as production costs are location dependent. The future of hydrogen report has made estimates for the cost of hydrogen varying in different countries (IEA, 2019). The report estimates the average cost of hydrogen production in China to be 1.9 $\$/kgH_2$ while the average cost in Australia was estimated to be 3 $\$/kgH_2$ (IEA, 2019). This variation in costs indicate that multiple options are available to import hydrogen from different regions. The cost of the energy carrier would be a major factor in deciding the region to import from but also the distance between the port of source and destination. As the distance increases between the source and destination, the cost of shipping and the boil off losses increase. To realise the impact of these factors on the import costs, a sensitivity analysis was done based on imports of hydrogen from three different countries taking into account the different costs using the estimates from the future of hydrogen report and considering the different distances. The distance and the time taken for shipping was estimated using https:/sea-distances.org/. The results of the sensitivity analysis is shown in figure 39.

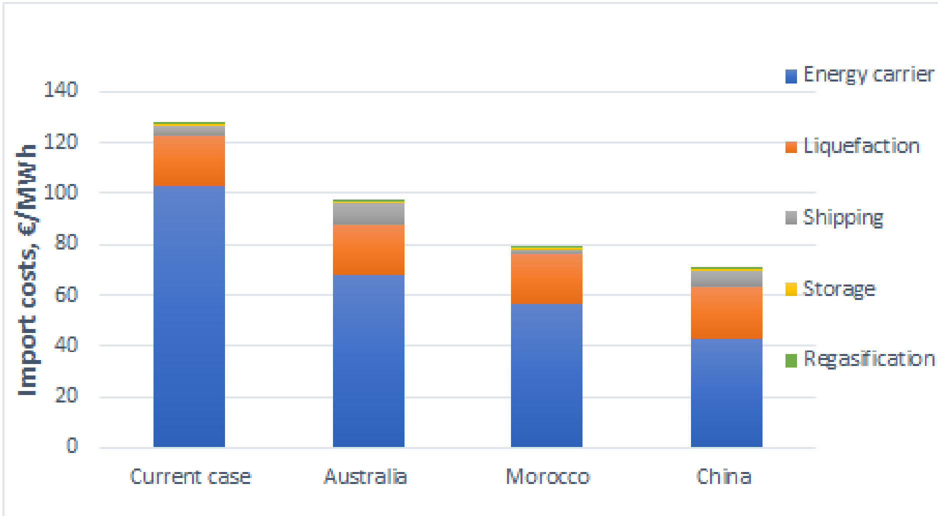

Figure 39: Import costs of hydrogen from different countries

As seen in figure 39, the cost of the energy carrier at the port of source is the dominant factor determining the import cost of the energy carrier. For the imports coming in from Australia and China, there is a notable increase in the shipping costs as a result of the longer distances of 21400 km and 19500 km the ships have to travel from Australia and China respectively. Despite the longer distances, importing hydrogen from China is still more economical than Morocco as the cost of hydrogen is lower.

10.7 Region specific costs across the Netherlands

As discussed in chapter 9, the costs of hydrogen delivered to the six industrial clusters varies from 130 - 165 €/MWh while the cost estimated for the country for hydrogen pipeline transport was 151 €/MWh. This was a result of the varying quantities of hydrogen at the different stages of the supply chain. A weighted average of the costs at each industrial cluster will be able to produce the estimated costs for the Netherlands. As seen in figure 26, the cost of hydrogen was the highest at Emmen while Chemelot had the lowest hydrogen cost. The high cost at Emmen was due to the fact that hydrogen was completely sourced from the production plant at Delfzijl. This reflects on the high production costs of hydrogen in the Netherlands, compared to less-expensive hydrogen imports. The high production costs alongside the storage and transport costs resulted in hydrogen to have a cost of 165 €/MWh when delivered to Emmen. On the other hand, Chemelot had the lowest cost due to it relying completely on imports coming in via the port of Rotterdam. Even when the storage and transport costs are added, imported hydrogen was delivered at a cost lower than domestically produced hydrogen. It has to be noted that Chemelot only receives imported hydrogen, since hydrogen produced in Rotterdam is consumed by Rotterdam and not transported elsewhere. From this, it can be inferred that the industrial clusters that receive imported hydrogen will have lower costs than the industrial clusters that have hydrogen electrolysers on-site. The allocation of the carrier domestically produced energy across the Netherlands will have an effect on the final cost of the energy carrier at each industrial cluster.

10.8 System level discussion

Analysing the results, hydrogen pipelines may seem to be the most probable energy carrier and transport mode to implement. Nevertheless, when analysing the costs on a transport route level, it can be noticed that road transport is a more economical option relative to pipeline transport for some routes, especially for routes with low transport quantities (ex. Delfzijl - Emmen or Rotterdam - Emmen). Therefore an optimal configuration of the transportation of the energy carriers across the Netherlands would be a more complex interconnected network of pipelines and road transportation as opposed to just considering one transport mode for the whole of the Netherlands.

In the case of ammonia pipeline transport, if the reforming costs were to be disregarded, ammonia pipelines would be more economical to implement than hydrogen pipelines as a result of lower import costs. This brings into question whether ammonia pipelines could be built and used for energy generation while hydrogen pipelines could be separately built for supplying the hydrogen feedstock demand of 96 PJ. There comes a dilemma as to whether only one energy carrier should be transported or whether multiple energy carriers should be transported across the Netherlands simultaneously, since it is also expected that there will be demand for the other energy carriers as feedstock. Therefore a possibility does exist, that in a low-carbon scenario, multiple energy carriers may be transported to satisfy the energy demand as well as the feedstock demand. The dominance of the energy carriers may be confined to specific regions where there may be a high demand for a particular energy carrier as feedstock, in which case the same energy carrier can also be used for energy production as well.

The hydrogen electrolyser in this thesis is assumed to be operating at a 80% load factor which brings it closer to be considered as a base load similar to coal and nuclear power plants. The uncertainty of power available from offshore wind farms, which has not been modelled in this thesis, is expected to play a role in determining the operating capacity of the electrolyser and also the cost of electricity, further having an impact on the system costs of the energy carriers. The gas for climate report by Navigant has estimated that hydrogen electrolysers powered from the North Sea offshore wind farms would be able to run at an operating capacity of 60%, which is expected to have an effect on the quantity of domestically produced hydrogen and the other energy carriers, eventually affecting the system costs of the carriers (Navigant, 2019).

It is expected that imported energy carriers will be relatively less expensive compared to domestic production as a result of constraints to generate cheap renewable energy to produce the energy carriers at a lower cost. This brings into question how much of the energy carrier should be imported and how much should be produced locally. The future of hydrogen report by IEA, suggests that for the case of Japan which has a hydrogen production cost of 6.50 $/kgH_2$, importing from Australia which has a lower production cost of just under 4 $/kgH_2$ would make more economic sense (IEA, 2019). This statement could also apply for the Netherlands which has restrictions in terms of area to produce cheap renewable electricity. As seen in section 10.5, lower electricity costs are essential for obtaining lower hydrogen production costs. Thereby importing energy carriers from Australia, the Middle east or North Africa, where an abundance of area and natural resources are available for renewable energy generation, could reduce the system costs of the energy carrier in the Netherlands.

Importing the energy carriers by pipeline is another option that can be considered instead of shipping the energy carriers. In the gas for climate report, Navigant has explored the option of hydrogen production in the south of Europe which is expected to have low electricity costs due to the abundance of solar energy in the region (Navigant, 2019). This opens up an opportunity to import energy carriers by pipeline from the south of Europe and further from the north of Africa as well, where countries like Morocco are expected to have surplus energy generation from photovoltaic technology.

Considering this option may eliminate the need to import hydrogen by ships, avoiding the need to liquefy and regasify the hydrogen, which eventually may lead to a better efficiency and lower system cost.

On a country level, the allocation of the imported and domestically produced energy carriers across the six industrial clusters will determine the cost of the energy carriers delivered to each of the industrial clusters. The impact of this allocation has been highlighted in section 10.7, where a disparity exists among the costs of hydrogen delivered across the six industrial clusters in the Netherlands. Therefore an optimised allocation of the imported and domestically produced energy carriers among the industrial clusters would be required, which would depend on the import and domestic production costs. This also opens up the possibility of importing the energy carriers to the other three industrial clusters of Delfzijl, Amsterdam and Zeeland which have ports capable of handling gas and liquid bulk. This would reduce the transport infrastructure required on land and also reduce the final cost of the energy carrier delivered to each of the industrial clusters.

10.9 Limitations

As discussed in section 10.8, many variations exist in estimating the system cost of the energy carrier in the Netherlands and at each industrial cluster. This shows that the thesis is limited to a high level analysis of the transportation of the energy carriers across the Netherlands. This research is carried out for the year 2050, when a low-carbon economy is expected, based on the current situation. Going forward 30 years, the situation in the Netherlands would have changed, from the number of industrial clusters present in the Netherlands to the size/demand of each industrial cluster. The change in the demand and possibly locations of the industrial clusters will have an impact on the transport network in turn affecting the system costs of the energy carriers. The domestic supply of hydrogen and further the energy carriers which is based on the surplus power available from the North Sea offshore wind farms by 2050 is an assumption and the reality may be different. The location and power available from the different wind farms may be influenced by changing wind patterns and other climate factors. Further, the power available onshore at each industrial cluster may depend on the growth of existing industrial clusters and the presence of new industrial clusters. This thesis also estimates the system costs of the energy carrier based on 2018 costs which is not representative of the costs at 2050.

By 2050, the technology required at each point of the supply chain would have become more mature resulting in a more efficient and cost effective energy carrier. Further the maturity of the various technologies may not be at the same level, with some technologies maturing faster than the other depending on the learning curve, which may influence the final outcome of this thesis. Other aspects such as the storage of gases (hydrogen and synthetic methane) in salt caverns or depleted gas fields have also not be considered in this thesis, which could result in a geographic dependent transport network with the energy carrier supply points concentrated near areas of depleted gas fields or salt caverns. The possibility of producing hydrogen offshore near the offshore wind farms and then transported by underwater pipelines to the Netherlands is a possible variation that is being researched but also not considered in this thesis (TenneT, Gasunie, & DNV GL, 2018). Further, this thesis also does not take into account the feedstock demand of the energy carriers which is expected to have an effect on the viability of using other energy carriers instead of hydrogen. Therefore, the results of this thesis are limited to the scope envisioned, with the possibility to further optimise the transport routes to enhance the results. A major limitation to this study is the lack of data available to perform the analysis, of which some of the data had to be extrapolated from old research material and assumed based on similarities of the energy carriers and processes.

11 Conclusions

This research was done to identify key techno-economic trade-offs and hotspots in the supply chains of different renewable based energy carriers for the Netherlands for the year 2050. To be able to identify these key factors, a techno-economic analysis was done based on a certain number of inputs and assumptions, which will be outlined in brief. The energy carriers shortlisted in this thesis include hydrogen, ammonia, methanol, dimethyl ether (DME) and synthetic methane. The demand for hydrogen in the Netherlands was projected to be 444 PJ or 3155 ktons of hydrogen by 2050, and was expected to be concentrated towards the six industrial clusters of Amsterdam, Chemelot, Delfzijl, Emmen, Rotterdam and Zeeland. In spite of the demand of 3155 ktons, only 1682 ktons of hydrogen could be produced in the Netherlands from 15 GW of surplus offshore wind power in the Netherlands. Hydrogen electrolysers were assumed to be present in the industrial clusters of Amsterdam, Delfzijl, Rotterdam and Zeeland, due to their proximity to the coastline. The shortage of 1473 ktons of hydrogen would have to be imported and is assumed to come in via the port of Rotterdam, by maritime shipping. On land, the energy carriers were expected to be transported by either pipeline or by road transport, which could be in compressed or liquid form. The system boundaries assessed in this thesis encompass production of the energy carrier, import of the energy carrier, storage at the source, loading, transport, unloading and storage at the destination. Since all the energy carriers have the ability to be directly used for energy generation, only hydrogen required for non-energy purposes had to be converted/reformed from the other four energy carriers. This value was assumed to be 96 PJ as taken from the Gasunie 2050 survey. Therefore the system boundaries for ammonia, methanol, DME and synthetic methane would also include reforming of these energy carriers back to hydrogen. Using the outlined case, a techno-economic analysis was performed to answer the three sub questions resulting in the answer of the main research question.

1) What key technical factors will influence the feasibility of transporting the hydrogen and hydrogen energy carriers the most?

The production of the energy carrier was the most energy intensive system component in the entire supply chain across all the energy carriers and transport modes. The efficiency of the hydrogen electrolyser is an important factor in determining the system efficiency, as it serves as the starting point in the supply chain of all the energy carriers. The efficiency further decreases across the supply chain as more components are introduced in the system. Transport pressures have an impact on the energy consumption of loading and unloading the energy carrier onto and from the transport medium, resulting in compressed road transport being a relatively inefficient transport mode. Ammonia reforming is an energy intensive process in comparison to the reforming of the other energy carriers, hindering ammonia from becoming a source for hydrogen demand at the destination.

2) How do the system costs compare with each energy carrier across the different transport modes?

Pipeline transport was found to be the most economical transport mode followed closely by liquid road transport. Hydrogen pipelines was the most economical transport mode and energy carrier followed by liquid hydrogen road transport and ammonia pipelines. Compressed road transport had a relatively high transport cost as a result of high loading and unloading costs due to high transport pressures, which further increased as higher transport pressure tube trailers were used. The production and import costs dominated the system costs for all the energy carriers in the different transport modes, except for compressed road transport where transport costs played a more dominant role.

Hydrogen production costs, which dominated the costs of production of the energy carriers, was influenced by the cost of electricity and the Capex of the electrolyser. Storage costs were relatively negligible while reforming costs were noticeable but still not a dominating factor contributing to the system costs, except in the case of ammonia. Liquefaction costs for hydrogen and synthetic methane resulted in higher import costs and higher liquid road transport costs.

3) Are there differences between region specific and country level costs and if so, which factors trigger these differences?

There was a clear variation in the costs across the six industrial clusters in the Netherlands with the weighted average of the costs at each industrial equal to the system costs of the energy carrier for the country. The variation in costs was an effect of the allocation of the domestic production of the energy carriers and the imports towards each industrial cluster.

What are the key techno-economic trade-offs and hotspots in the supply chain of different renewable based energy carriers for a low-carbon scenario for the Netherlands in 2050?

The hydrogen electrolyser efficiency has a paramount effect on the efficiency of the whole system across all the energy carriers and the transport modes. The cost of electricity is an important parameter affecting production, loading and unloading costs, in turn affecting the system costs. Very high transport pressures have a profound effect on the efficiency and system costs of the energy carrier. The need to liquefy hydrogen and synthetic methane for maritime shipping resulted in more expensive imports relative to the other three energy carriers, and further had an effect on the transport costs when transported as a liquid by road. The reforming of ammonia for hydrogen production at the destination is energy demanding and expensive, hindering ammonia from becoming a competitive energy carrier. A trade-off between how much of the energy carrier that should be domestically produced and imported, will have a major effect towards the system costs of the energy carrier in the Netherlands. The allocation of the imported and domestically produced energy carriers across the industrial clusters in the Netherlands has an influence on the final cost of the energy carrier delivered to the industrial clusters.

11.1 Recommendations

Based on the results from this thesis, the production of the energy carrier in specific the hydrogen electrolyser, is the most energy consuming and cost contributing system component. Therefore, further research should focus on improving the efficiency of the hydrogen electrolyser while reducing the Capex. The loading and unloading of the energy carrier onto and from the transport medium using compressors and pumps require a large amount of power. Therefore, improving the efficiency of existing compressors and pumps or investigating new compression technologies will contribute to not just a better system efficiency but will also lower the system cost especially in the case of compressed road transport. Process improvements or investigating new methods for the liquefaction of hydrogen and synthetic methane will be able to reduce the liquefaction costs, resulting in less expensive imports coming into the Netherlands and lower system costs when transported by road as a liquid. More research focused on scaling up ammonia electrolysers to industrial levels or process improvements in the auto-thermal reforming of ammonia, will make ammonia a more competitive energy carrier on a system level with respect to hydrogen.

Focusing on the methodology employed in this thesis, a fixed scope is taken into consideration not accounting for: the variability in the location of and power supplied by the offshore wind farms, other ports for importing the energy carrier, and the growth/demand of the industrial clusters. Therefore, further research on this topic should consider these variations to be able to make a more accurate model for cost and efficiency estimations. Further work on this topic should also consider the demand for the other energy carriers as feedstock, which is expected to have an impact on the system costs. One of the main reasons to switch to a low-carbon society is due to the environmental impacts of currently used fossil fuels, therefore the environmental impacts of the supply chain including the utilisation of the energy carriers at the destination is an important parameter to account for in further research. To get a more holistic understanding of the supply chain, the offshore wind farms or any other energy generation system that is used, should be modelled to account for the variability in power generation and its impacts on the rest of the system.

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