Offshore green hydrogen production and transportation to shore via pipelines in the North Sea with parallel natural gas transport

Konstantinos Siachos

Master Thesis

TU Delft

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A techno – economic analysis

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by

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Preface

This thesis is the final research study, concluding my MSc in Sustainable Energy Technology at Delft University of Technology. This project, which was a collaboration between TU Delft, Guidehouse, and myself, has been a challenging yet rewarding experience, enhancing my knowledge, and improving my perception at many levels.

First of all, I would like to thank prof. dr. Ad van Wijk, my supervisor from TU Delft, for his guidance during this thesis, as well as for the chance to work on such an interesting project in the first place. His broad knowledge and experience on carbon-free energy systems and hydrogen in particular proved to be extremely beneficial throughout the entire thesis procedure. I would also like to express my gratitude to Bob Prinsen and Marissa Moultak, my supervisors from Guidehouse, for their guidance along this great journey, for supporting and motivating me, and for introducing me to the fundamentals of energy consulting. Furthermore, I would like to thank Ron Hagen, Menno Ros, Hans Janssen, and Kees Mark from NGT and NOGAT, Wouter van de Graaf from Gasunie, and the entire Guidehouse team for their valuable help. Moreover, I would also like to thank my thesis committee members prof. dr. ir. Zofia Lukszo and prof. dr. Kornelis Blok from TU Delft for evaluating my work and helping improve it. Last but not least, I would like to thank my family for their love and constant support throughout this journey.

Konstantinos Siachos

Delft, November 2022

Summary

The North Sea has significant potential in becoming a green energy hub, due to its remarkable offshore wind potential, and could therefore facilitate the energy transition to a net-zero energy system in Europe in the coming decades. In this transition, hydrogen is also predicted to play a key role, due to its ability to transport and store substantial amounts of energy. Previous studies have shown that for large offshore wind capacities and substantial distances from the shore, transporting the produced energy in the form of molecules (converting the electricity to hydrogen) via dedicated pipelines would be a more cost-effective option than using electricity cables and converting electricity to hydrogen onshore (Groenemans et al., 2022; van Wijk, 2021b). This transport could be achieved by developing new hydrogen-dedicated infrastructure or reusing existing natural gas pipelines, which is a cost-effective alternative. Apart from the potential hydrogen developments, the North Sea is still home of numerous offshore natural gas fields, the exploitation of which could contribute to reducing energy scarcity, reducing energy prices, and enhancing the region's energy security and independence. The importance of hydrogen for decarbonizing hard-to-abate sectors has also been underlined by the European Commission with the REPowerEU package. Specifically, the REPowerEU package highlighted the need for accelerating the rollout of the technology, aiming for 10 million tons of green hydrogen production by 2030 (European Commission, 2022).

This research study aims to determine the potential for repurposing existing gas infrastructure in the North Sea for hydrogen transport, taking into consideration that this infrastructure will still have to transport natural gas to the shore over the coming years. Redirecting an amount of this natural gas to other, neighboring pipelines creates the possibility for existing pipelines to be freed up for hydrogen transportation, and therefore achieve parallel transmission of green hydrogen and natural gas from the Dutch North Sea to the shore. Consequently, the purpose of this thesis project is to examine the geographical, technical, and economic feasibility of large-scale green hydrogen transportation (produced offshore with green energy from wind turbines), with parallel natural gas transport, via new and already existing gas infrastructure in the North Sea, by 2030.

The first aspect to be analyzed was the geographical configuration of such a system. For that purpose, different possible configurations for parallel transport of hydrogen and natural gas via existing North Sea infrastructure were examined. This analysis indicated that the most suitable scenario, considering the projected timeline and current circumstances, would be repurposing the NGT pipeline for 100% hydrogen transportation (produced from offshore wind search areas 7 and 3), and rerouting the natural gas to the NOGAT pipeline. Both NGT and NOGAT pipelines are parts of the North Sea offshore pipeline system, currently transporting natural gas to the Dutch shore. The next part of the study concerned the physical configuration of the hydrogen transportation system. A component analysis was done, highlighting the most suitable components across the entire system configuration, including the offshore hydrogen production by water electrolysis, its compression, and its transportation via the NGT pipeline among others.

Furthermore, a more elaborate analysis was done to determine the project's technical feasibility, with emphasis being placed on the key aspects of hydrogen compression and transportation, evaluating its flow characteristics and compression requirements. The analysis results showed that transporting hydrogen via the NGT pipeline to the Dutch shore is technically feasible. Based on the analyzed scenario, the maximum hydrogen transport capacity was found to be 7.9 GW, and the total

compression capacity 103 MW. During its transportation along the length of the pipeline (253 km), hydrogen experiences a pressure drop of 10.4 bar (65 bar to 55 bar). An economic evaluation of the system was also performed, indicating that the project is feasible from a financial standpoint as well. The overall LCOH transport for the proposed system, including hydrogen compression and NGT pipeline repurposing costs, was found to be 0.17 €/kg/1000km. To put that number in perspective, the cost of hydrogen production at sites with high renewable energy potential is expected to be approximately 1 €/kg around 2030 (Singlitico et al., 2021; van Wijk, 2021a). The overall conclusion of this study is that reusing existing infrastructure in the North Sea for hydrogen transportation is a physically and technically feasible option, which can be achieved at a competitive cost.

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Nomenclature

Abbreviation	Definition
SMR	Steam Methane Reforming
HVDC	High Voltage Direct Current
DC	Direct Current
AC	Alternating Current
EU	European Union
EC	European Commission
MEP	Member of the European Parliament
TSO	Transmission System Operator
NSEC	North Seas Energy Cooperation
LNG	Liquified Natural Gas
PVC	Polyvinyl Chloride
PE	Polyethylene
LCOH	Levelized Cost of Hydrogen
LCOE	Levelized Cost of Electricity
SA	Search Area
NOGAT	Northern Offshore Gas Transport
NGT	Noordgastransport
QGIS	Quantum Geographic Information System
AWG	Ameland Westgat
boe	Barrels of Oil Equivalent
FSA	Formal Safety Assessment
PEM	Proton Exchange Membrane
TDC	Top Dead Centre
BDC	Bottom Dead Centre
MW	Molecular Weight
HFS	Hydrogen Fueling Station
NG	Natural Gas

EHB	European Hydrogen Backbone
ΔP	Pressure Drop
HHV	Higher Heating Value
LHV	Lower Heating Value
ΔH	Elevation Difference
Re	Reynolds Number
SI	International System of Units
NTP	Normal Temperature & Pressure
NREL	National Renewable Energy Laboratory
PV	Photovoltaic
NIST	National Institute of Standards and Technology
CAPEX	Capital Expenditures
OPEX	Operating Expenses
O&M	Operation and Maintenance
TCI	Total Capital Investment
CRF	Capital Recovery Factor
WACC	Weighted Average Cost of Capital

1

Introduction

1.1 Hydrogen’s Role in Enabling Climate Neutrality

Hydrogen (H_2) is expected to play a significant part in the energy transition towards carbon neutral energy systems as a zero-emission energy carrier, when produced in conjunction with electricity from renewable sources (green hydrogen). To date the vast majority of the hydrogen produced globally has come from coal or natural gas, also known as ‘grey hydrogen’, resulting in significant carbon emissions. Specifically, in 2019, grey hydrogen accounted for around 98% of the total hydrogen produced, being the source of around 830 Mt of carbon emissions yearly (Ochu & Braverman, 2021). Currently, 76% of global hydrogen production is achieved through steam methane reforming (SMR), 22% via coal gasification processes, and only 2% comes from electrolysis (Ochu & Braverman, 2021). Currently hydrogen is mainly used in petrochemical/chemical industries and more specifically for refining oil, manufacturing steel by reduction of iron ore, manufacturing of ammonia, and production of methanol (IEA, 2019). Given that almost the entirety of those sectors has been historically using ‘grey hydrogen’ produced from fossil fuels, there is a substantial opportunity to reduce emissions and decarbonize those manufacturing processes by transitioning to green hydrogen feedstocks. In a future net-zero energy system hydrogen has the potential of playing another crucial role, that of a carbon-free energy carrier since its gravimetric energy density is exceptionally high. This could enable hydrogen to become a means of storing and transporting energy in bulk volumes and also decarbonize energy consumption in hard-to-abate sectors (van Wijk, 2021b).

Green hydrogen can be easily produced via the electrolysis of water. Recent significant advancements in both electrolysis and the production of renewable energy have made it possible for green hydrogen to be produced at a competitive price (Calado & Castro, 2021). Electrolysis is the process during which water is split into its two components: hydrogen (H_2) and oxygen (O_2) using electricity. For green hydrogen the required electricity can be acquired from the utilization of renewable sources (e.g., solar, wind, etc.) In order to achieve a competitive price for the green hydrogen produced, a crucial factor is low electricity price. Low-cost renewable energy production can be typically found within a great distance from the demand sites, since the most promising areas for cheap electricity production are located in remote areas with great solar and/or wind potentials, for example in desert sites with high levels of solar irradiation or at sites with high wind speeds (onshore and offshore). Therefore, to exploit high solar and wind energy potentials and at the same time satisfy high demand regions, renewably produced electricity needs to be converted into hydrogen, enabling its long distance transportation (via ships or pipelines) and its long term storage (in exploited gas fields or salt cavern formations) (van Wijk, 2021b).

1.2 Energy Independence

The recent developments in Ukraine have deeply affected Europe's energy supply, leading energy prices to a record high. As announced by the European Commission, Europe will move in the direction of becoming independent from Russian oil and gas, before 2030 (Reed, 2022). This is planned to be achieved by saving energy, accelerating renewable energy developments, increasing energy imports from countries like the U.S.A., Egypt, or Qatar, and taking advantage of existing oil and gas reserves located in European ground. By diversifying the energy supply, Europe could increase its energy security and ultimately maintain a stable energy network.

Specifically, the Netherlands, that in 2021 spent around €16 billion on Russian fossil fuels, is looking for alternatives (Vasques, 2022). These include speeding up renewable investments, realizing additional import routes, and also taking advantage of the natural gas resources in the North Sea. The largest gas field located in the Netherlands is the Groningen field. However, the Dutch Government halted the gas extraction activities from October 2022 in order to limit potential seismic activity risks in the surrounding area (EURACTIV, 2022). On the other hand, more and more energy analysts and industry experts believe that restarting gas production from the Groningen Gas field would help solve the energy security issue (EURACTIV, 2022), although such an action would only have a short-term effect, without contributing to the long-term decarbonisation target.

1.2.1 REPowerEU: Phasing Out Russian Fossil Fuels

Since the outbreak of the war in Ukraine, the European Union has been trying to find ways to break its ties with Russian energy. EU leaders have agreed to phase out and eventually quit Russian fossil fuels as soon as possible, however a lot of developments need to be made for this difficult target to be achieved in time, without endangering Europe's energy security.

The EU has rallied in support of Ukraine since the country was invaded by Russia in February 2022. EU leaders have agreed on sanctions against Russia and has also provided aid to Kiev, however replacing Europe's imported fossil fuel supply with other options proved to be hard and time consuming. Within the first two months of the war, EU imported fossil fuels worth of approximately € 44bn, which is almost double EU's fossil imports for 2021 for the same period of time (Harvey, 2022). While the EU is making progress towards sanctioning coal and crude oil imports from Russia, the main focus is on how to reduce Europe's dependance on Russian natural gas. In 2021, the percentage of the EU's natural gas imports from Russia was around 43.5% (155 bcm), with Norway, Algeria, and the US following with 23.6%, 12.6% and 6.6% respectively, as can be also seen in the chart of Figure 1.1 (European Commission, 2022a; IEA, 2022). The majority of these imports arrived in Europe via pipelines, whereas a rising portion of them have been in liquid form (LNG) coming mainly from the

United States, who keeps on increasing LNG exports to Europe on a yearly basis (European Commission, 2022a).

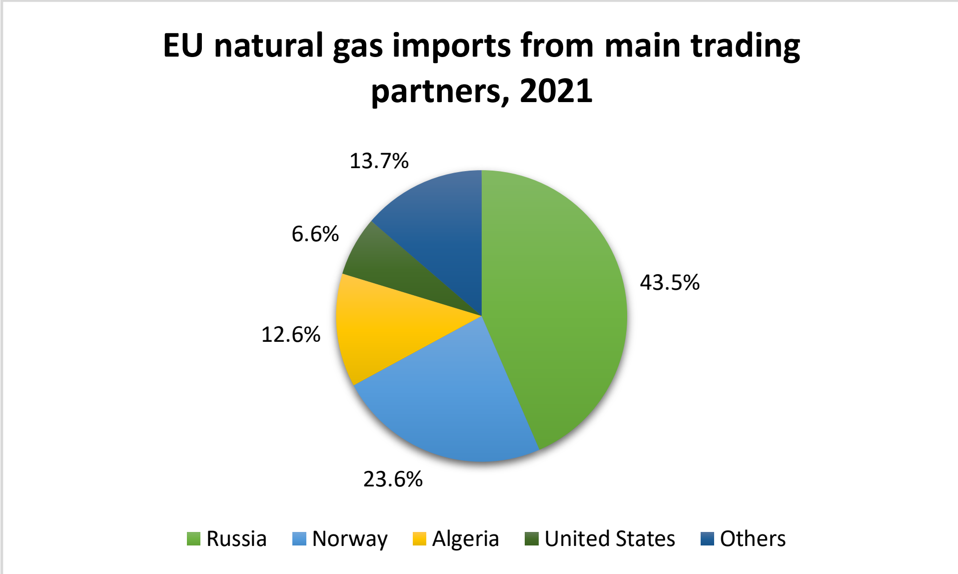

Figure 1.1: European Union natural gas imports from main trading partners for 2021 (European Commission, 2022a)

In March 2022, the European Commission (EC) put forward its plan to replace Russian fossil fuels, namely REPowerEU. This plan has three main elements: increasing energy savings, accelerating the clean energy transition, and diversifying the EU gas supply away from Russia, as depicted in Figure 1.2 (European Commission, 2022b). More specifically, energy savings are a quick way to reduce energy consumption, which would in turn reduce reliance on Russian natural gas.

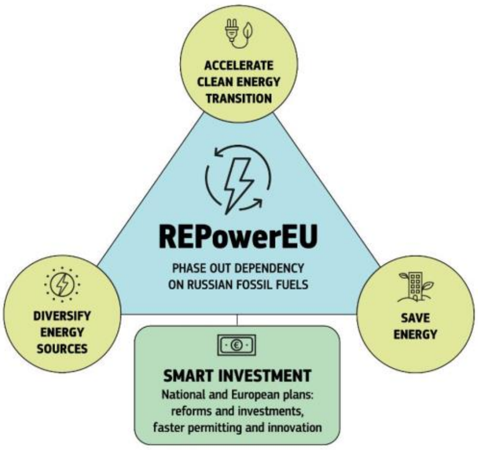

Figure 1.2: REPowerEU: 3 main elements for reducing dependency on Russian fossil fuels (European Commission, 2022b)

The REPowerEU package was accompanied by a hydrogen accelerator, highlighting hydrogen as a critical component for decarbonizing hard-to-abate sectors, for example maritime, aviation, as well as various industries. The idea of the hydrogen accelerator was proposed by the EC in the REPowerEU package in order to achieve an even quicker rollout of the technology. Specifically, the EC outlines efforts to ramp up hydrogen supply and demand on an even higher level than in the 2020 strategy for hydrogen (European Commmission, 2022). REPowerEU aims to have a renewable hydrogen production level of 10 million tons by 2030, a number that is almost doubled compared to the 5.6 million tons target already envisaged by the EU framework to decarbonize gas markets, also known as 'Fit for 55' (Hume, 2022). In addition to that, REPowerEU targets another 10 million tons of renewable hydrogen imports from foreign countries, raising the overall target to 20 million tons by 2030 (European Commmission, 2022).

In REPowerEU the EC also increased the EU's 2030 energy savings target, a move that will bolster efforts by Members of the European Parliament (MEPs) to increase ambition and also give a strong signal to the industry. Specifically, the target for energy savings has been raised to 40% (final energy consumption) and 42.5% (primary energy consumption), corresponding to 740 and 960 Mtoe of energy savings respectively (European Parliament, 2022). Furthermore, the EC also increased the proposed 2030 renewable energy target (under discussion between European governments and MEPs), from 40% to 45%, over double Europe's current capacity (European Parliament, 2022). The third part of the REPowerEU package focuses on diversification of EU's energy sources and mainly its gas supply. This includes agreements on liquefied natural gas (LNG) imports with exporters like the US, Canada, and others, hoping that these fossil gas providers will ultimately become suppliers of renewable gases, e.g., hydrogen. The EC's goal with the REPowerEU plan is to reduce EU's gas consumption by two thirds by the end of 2022. After that, there will be a more gradual reduction due to the long time necessary to build up renewable energy capacity. In order to make the targets set by the REPowerEU plan become a reality, there is still much work to be done. For instance, permitting has been a main obstacle for renewables deployment, and particularly for offshore wind. However, the EU has put forward guidance on how countries can change this.

1.2.2 The Role of the North Sea

The North Sea, due to its significant renewable energy potential, but also its existing oil and gas reserves, could also be a crucial part of the REPowerEU package. Specifically, harnessing the region's offshore wind energy potential could assist in reaching the target of 45% renewables in EU's 2030 energy mix, but also newly explored gas fields in the North Sea could be utilized to enhance the diversification of the region's gas supply. Both the UK and the Netherlands have approved natural gas projects (tapping into new gas reserves): UK regulators gave approval for the Jackdaw gas field to be developed by Shell, and the Dutch government declared the authorization of a joint German – Dutch gas exploration project in the North Sea (prior to the outbreak of the war) (Euronews, 2022). In May 2022, the leaders of the European countries surrounding the North Sea (Netherlands, Germany, Denmark, Belgium) took part on an Offshore Wind Summit, together with the EC president, declaring that there was an agreement to increase the combined offshore wind capacity of the region to 150 GW by 2050 (Wind Europe, 2022) These developments strongly indicate that the North Sea is becoming a pan-European hub, crucial for the development of renewable energy capacity, as well as for the phasing out of Russian gas imports.

Furthermore, the North Sea hosts numerous pipelines for natural gas transportation, constituting a vast energy transportation network. These pipelines are located in the continental shelfs of all surrounding countries (Netherlands, Belgium, Germany, UK, Denmark, and Norway), with many of them also realizing cross-border gas transportation. These pipelines, apart from transporting natural gas to the shore, also have the possibility to be retrofitted for hydrogen transportation. In line with the REPowerEU ambition to accelerate the development of a European hydrogen market in order to increase its energy system resilience, this existing infrastructure could play a key role in transforming the North Sea to a hydrogen production location for northern European markets (European Hydrogen Backbone, 2022). According to the European Hydrogen Backbone's 2022 publication, this hydrogen supply interconnected corridor is very likely to emerge, based on numerous planned and ongoing projects within the North Sea. More specifically, the region includes a great number of offshore wind projects, various large-scale H_2 integration projects, and could also host ship imports of hydrogen derivatives (e.g., liquid H_2, ammonia, methanol) in order to satisfy the demand in the main industrial clusters of the Netherlands, the UK, Belgium, Germany, Denmark, France, and Norway (European Hydrogen Backbone, 2022). The North Sea hydrogen corridor, as presented in the European Hydrogen Backbone is depicted in the map of Figure 1.3.

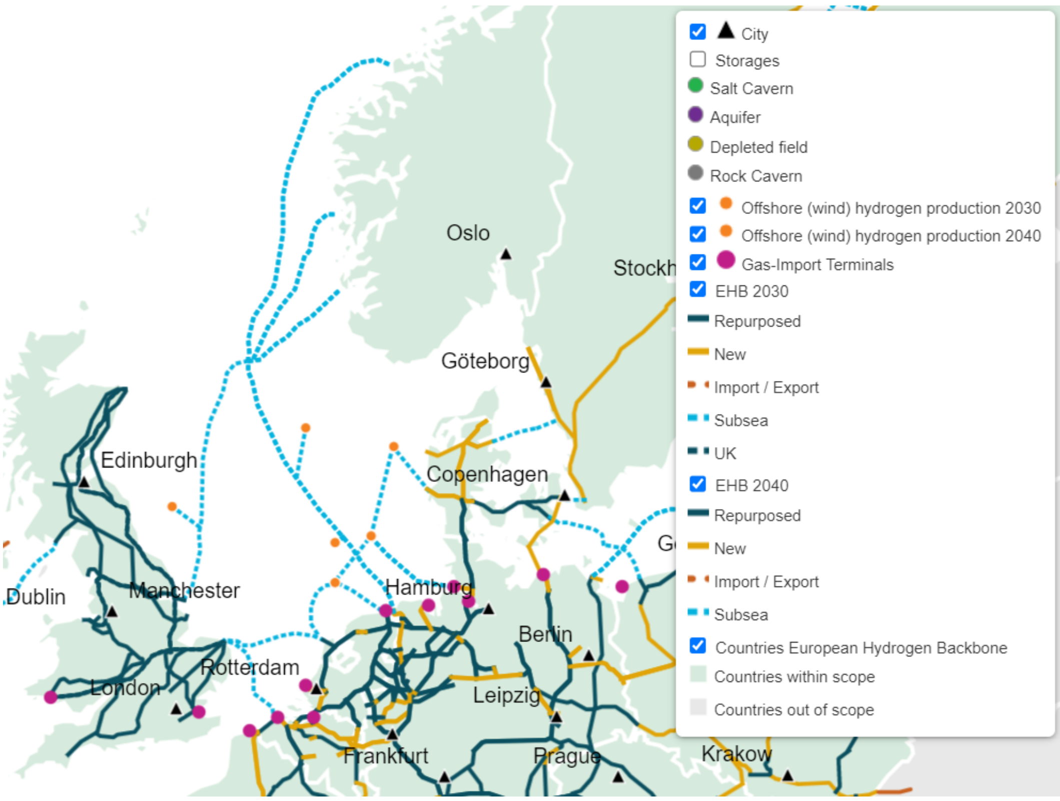

Figure 1.3: North Sea corridor for the supply of hydrogen to continental Europe – 2040, as proposed by 31 gas TSOs (European Hydrogen Backbone, 2022)

1.3 Offshore Energy Production: Transportation to the Shore

As explained in Section 1.1, high renewable energy potentials can be usually found in remote areas, such as deserts or offshore locations within large distances from the shore, for solar and wind power respectively. Specifically for wind energy, higher and more consistent wind speeds can be typically found offshore, resulting in producing higher levels of energy per installed wind turbine (Calado & Castro, 2021).

For offshore wind, there is the challenge of which is the most efficient and economical way to transport the produced green energy to the shore. Typically, offshore wind turbines are interconnected with the shore via electricity cables for the transportation of the produced electricity. However, High Voltage Direct Current (HVDC) cables (used for long-distance electricity transmission at high levels of power) are usually expensive because of the converter stations that are required at both ends of the transmission line, and that alternating current (AC) power cables have significant losses due to their high capacitance (Calado & Castro, 2021). For these reasons, another long-distance energy transportation solution is examined: that of transmitting energy to the shore in the form of hydrogen via pipelines. Transporting a gas through a pipeline includes no molecule losses. In comparison, energy transport in the form of electricity includes power losses across the powerline. However, in the case of hydrogen transport via pipeline, compression energy is required for the gas to reach its destination and compensate for the pressure loss over the pipeline (Miao et al., 2021; Panfilov, 2016; van Wijk, 2021b). Furthermore, pipelines generally have higher energy transmission capacity than power cables, a fact that makes the normalized capital expenditures of the pipelines lower than offshore cables for the transmission of the same amount of energy, in case large transmission capacities are required (Miao et al., 2021).

1.4 Hydrogen Transport via Pipelines

Given that in the coming decades the energy transition will be further accelerated, with a target of a net-zero greenhouse emissions by 2050, hydrogen is projected to play a key role in decarbonizing Europe’s energy systems with multiple applications. A crucial role for hydrogen would be that of an energy carrier, capable of transporting energy in large distances. In a future energy system hydrogen production would take place nearby the energy resource location, as this would imply significant cost benefits (cheaper green hydrogen production at sites with high green energy potential, e.g., solar, wind etc.) (van Wijk, 2021b). The produced hydrogen could then be transported to the demand site – usually large distances from the production site by various methods.

A cost-effective method to transport hydrogen over substantial distances would be via pipeline. Over such distances, hydrogen transportation via pipeline could be significantly less expensive than electricity transportation via cables, specifically when large total transmission capacities are required (DeSantis et al., 2021). Figure 1.4 depicts the differences in terms of amortized transmission costs between electricity transport via cable and other transportation options (H_2 pipeline, natural gas pipeline, oil pipeline etc). These differences mainly come down to two reasons: Firstly, an HVDC electrical cable’s capacity is notably lower than the capacity of a pipeline for hydrogen transport, and secondly, HVDC cables’ resistance leads to energy losses along the length of the electricity transport cable (van Wijk, 2021b). On the other hand, transporting molecules via pipeline include no energy losses, however the main cost driver in this case would be the compression energy required to compensate for the pressure losses along the pipeline.

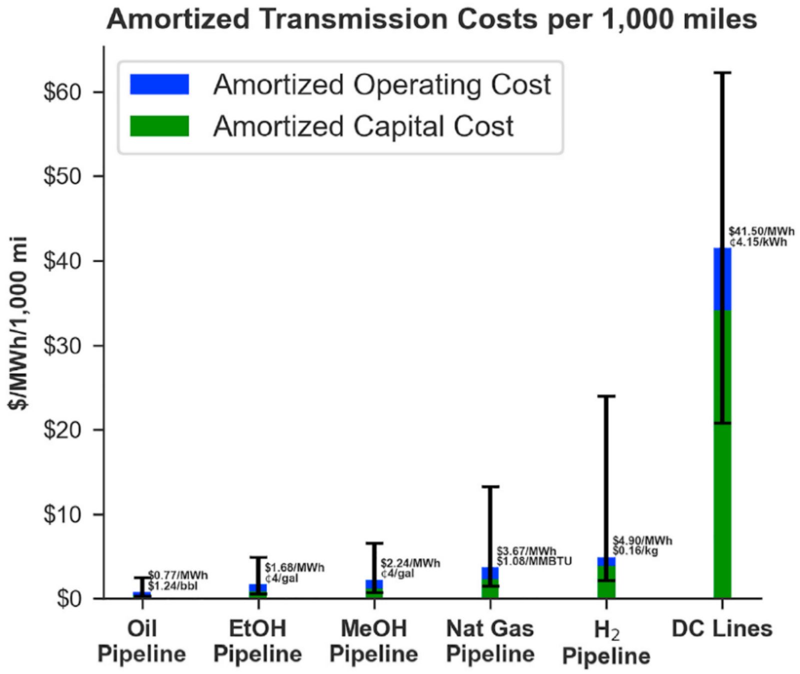

Figure 1.4: Amortized Energy Transportation Costs, per 1000 miles (DeSantis et al., 2021)

1.4.1 Repurposing Natural Gas Pipelines for Hydrogen Transport

Despite hydrogen's potential to drastically reduce carbon emissions, one of the major bottlenecks when it comes to replacing natural gas is the creation and deployment of new transportation infrastructure (Bossel, 2006). However, an advantage of transporting energy in the form of hydrogen via pipelines vs HVDC electricity cables, is that there is the possibility of re-using the existing gas infrastructure and therefore further reducing the overall energy transport cost.

In fact, the largest part of the existing natural gas infrastructure has the potential to be reused to host hydrogen transportation, which is also the case for the North Sea region. By repurposing existing gas pipelines and strategically developing new ones, the envisioned hydrogen backbones could be achieved in a quick and relatively inexpensive way (European Hydrogen Backbone, 2022; van Wijk, 2021b). As already mentioned, those planned hydrogen backbones, supported by numerous European gas TSOs, are going to link low-cost hydrogen production locations (high renewable energy potential) with the demand sites. With only a few exceptions, the existing natural gas infrastructure in Europe can handle 100% hydrogen transportation (van Wijk, 2021b). Pure hydrogen can be carried in gas transmission pipelines (as well as in distribution pipelines, which are usually produced of PVC or PE), whereas other system components like flow meters and compressors must be modified or even replaced (European Hydrogen Backbone, 2020; Kiwa Technology B.V., 2018; van Wijk & Chatzimarkakis, 2020).

1.5 Aim & Research Questions

As analysed in Section 1.2.2, the North Sea has a significant potential to become a hub for the energy transition, due to its remarkable offshore wind potential, and could therefore further facilitate the energy transition in the coming decades. At the same time, the North Sea is still home to numerous natural gas fields, the exploitation of which could assist in phasing out Russian fossil fuels and enhance Europe's energy security and independence. Redirecting an amount of this natural gas to other neighbouring pipelines, creates the possibility for existing pipelines to be freed up for hydrogen transportation, and therefore to achieve green hydrogen and natural gas transmission at the same time. Consequently, this study aims to examine the geographical, technical, and economic feasibility of large-scale green hydrogen transportation (produced offshore with green energy from wind turbines), with parallel natural gas transport, via new and already existing gas infrastructure in the North Sea, by 2030. The research was led by the following research question:

How could the offshore infrastructure system in the North Sea be reused for green hydrogen transportation, with parallel natural gas transportation?

To answer this question, an elaborate analysis is required, regarding the techno-economic implications of the re-purposing of gas pipelines in the North Sea for the transport of hydrogen and natural gas. Therefore, the following questions are formulated to help reach an answer to the main research question:

- How will such a system physically look? What would be a possible configuration of offshore hydrogen production in the North Sea, when utilizing existing and new infrastructure?
- What are the technical characteristics of hydrogen transportation via pipeline in the North Sea?
- What is the levelized cost of the hydrogen (LCOH) transport?

1.6 Thesis Report Outline

The structure of this thesis report is as follows. Chapter 2 presents an elaborate analysis of the geographical layout of the system, examining different scenarios for the parallel hydrogen and natural gas transportation via existing North Sea infrastructure. In Chapter 3, the physical configuration of the system are discussed, analysing its key components. Chapter 4 analyses the modelling of the proposed system in two levels: technical and economic, and describes the methodology used. In Chapter 5, the results of the system modelling, both technical and economic, are presented. Chapter 6 includes a discussion of the main results and general outcomes and, finally, Chapter 7 presents the conclusions of this study and provides recommendations for further research.

2

Geographical Configuration of the System

In the following section, an in-depth analysis of the geographical configuration of the examined system will be made, for simultaneously transmitting green hydrogen and natural gas to the shore through North Sea's infrastructure, highlighting the importance of the region's energy security. After a detailed analysis of the offshore wind and natural gas developments in the region, two potential scenarios will be examined for the parallel H_2 and gas transportation.

2.1 Current Situation in the North Sea

The North Sea is a region with multiple energy resources, ranging from numerous offshore oil and gas fields to significant offshore wind potential, as explained in previous section. Exploitation of the oil and gas fields in the North Sea has been going on since the mid-1900s up to this day. Despite the need for decarbonization of Europe's energy systems, the current developments following the Russian invasion in Ukraine dictate that all existing energy resources within the European region need to be exploited to increase the continent's energy security. In particular, the European Commission issued the REPowerEU plan in order to ensure Europe's security of energy supply and gradual disengagement from Russian gas imports by 2030. The main pillars of the REPowerEU plan concern the diversification of gas supply sources, decreasing demand, and increasing green energy output.

Therefore, to realize diversification of gas supply and, thus, increase Europe's energy security and at the same time accelerate the energy transition by utilizing more and more offshore wind resources, some major system reconfigurations are necessary. Particularly for the case of the North Sea, existing and newly explored natural gas fields need to be exploited and simultaneously the region's offshore wind potential needs to be harnessed.

2.2 North Sea Offshore Wind Energy Potential

The North Sea is a location with substantial green energy potential, mainly offshore wind. This fact has transformed the North Sea area into an offshore wind hub, playing a key role in achieving Europe's energy transition towards a sustainable future. In fact, the North Seas Energy Cooperation (NSEC) has agreed upon surpassing 260 GW of offshore wind capacity by 2050 (≥ 85% of EU's offshore wind pan-European target for 2050, reflecting its vast potential (Durakovic, 2022; North Sea Wind Power Hub, 2021). The countries surrounding North Sea have already been active in converting the region into an energy transition hub with most focus placed on offshore wind. Specifically, the Netherlands, Germany, Denmark, and Belgium are planning to develop a minimum of 150 GW of offshore wind capacity by 2050 (DW, 2022), and the UK, being the offshore wind leader in the region, is planning for an offshore wind capacity of 40 GW by 2030 (Cuff, 2019). The ongoing offshore wind developments in the North Sea can be seen in the map of Figure 2.1.

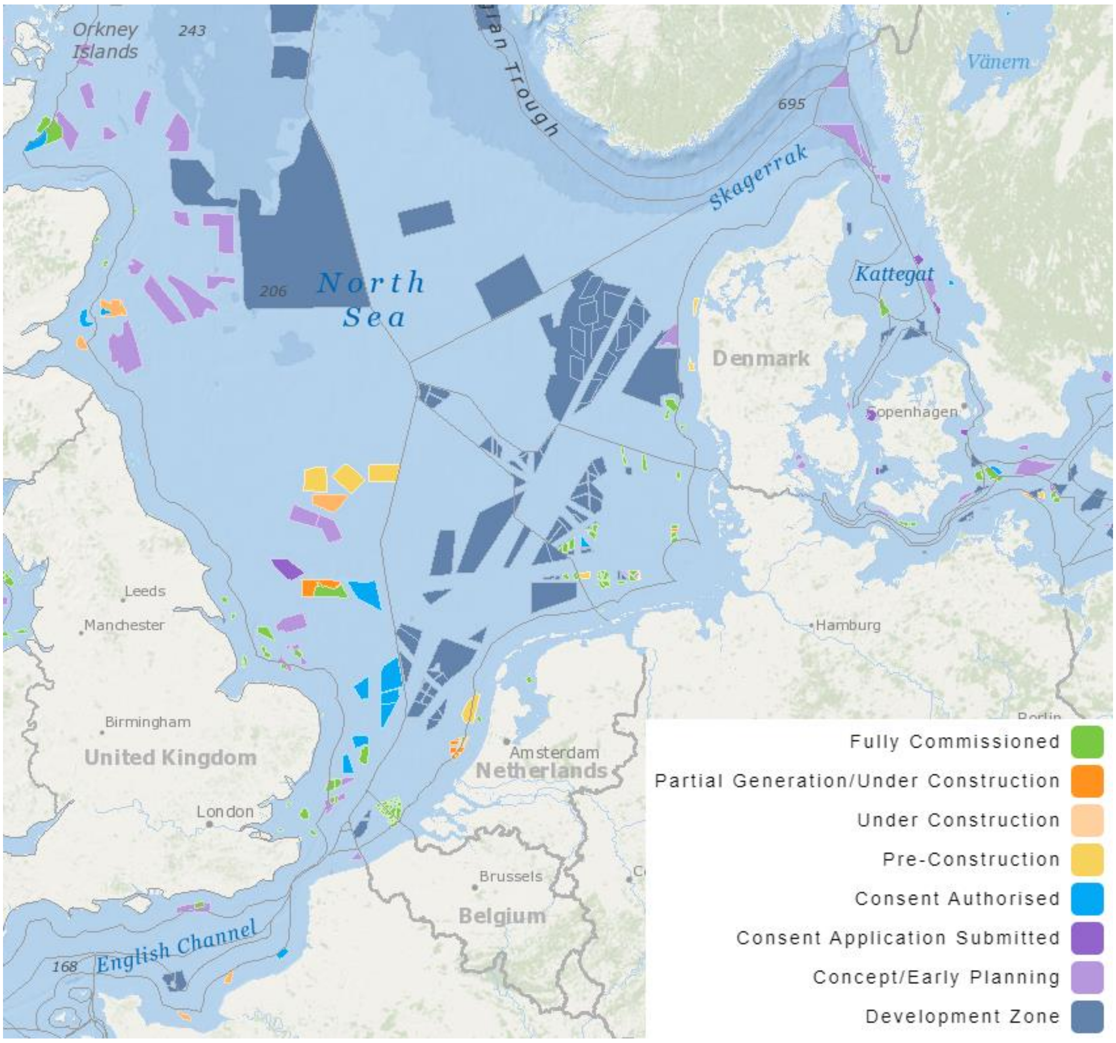

Figure 2.1: Offshore wind developments in the North Sea region (4C Offshore, 2022)

Specifically for the Netherlands, the country's offshore wind capacity in 2021 was approximately 2.5 GW, with a target to reach a minimum of 4.5 GW by 2023 (Wind Europe, 2022). The 2030 target for the Netherlands was initially announced to be around 11 GW of offshore wind capacity (Government of the Netherlands, 2021), but then got increased to 21 GW, indicating the Dutch government's strong commitment to accelerate the offshore wind developments in the North Sea. The roadmap for the offshore wind energy developments in the Dutch continental shelf of the North Sea is depicted in the map of Figure 2.2. Specifically, this road map includes details on the exact sites the wind farms will be developed, as well as the expected timeline for each wind farm project. This road map clarifies the situation for all stakeholders, establishes confidence for wind farm developers, and gives a clear picture of how the offshore wind developments are going to look like in the coming years in the North Sea (Government of the Netherlands, 2021).

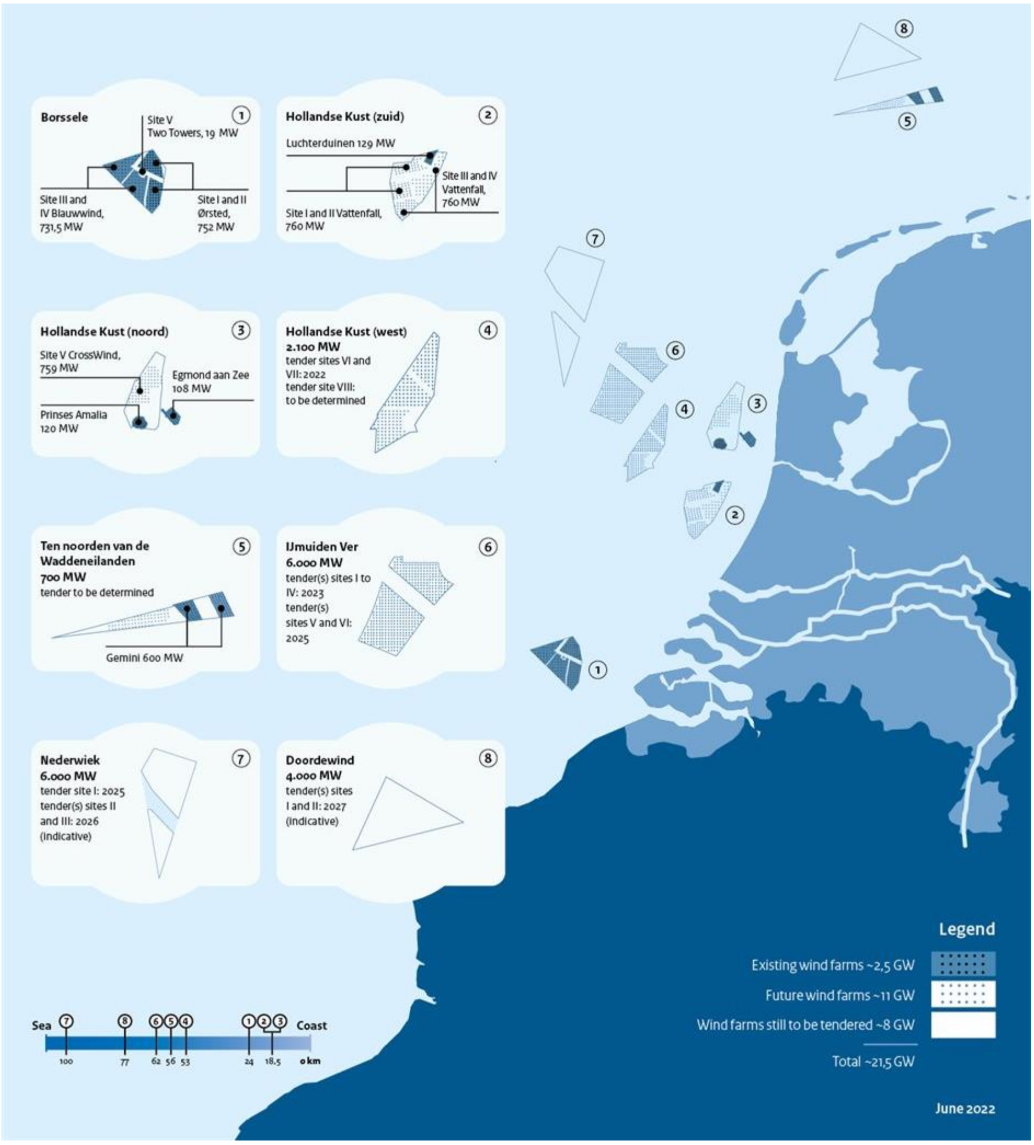

Figure 2.2: Offshore wind energy roadmap 2030 – Dutch continental shelf (Rijksoverheid, 2022a)

The Borssele wind farm zone (indicated as site No.1 in Figure 2.2) is already completely built, hosting a total of five sites, whereas Hollandse Kust (south) as well as Hollandse Kust (north), indicated as sites

No.2 and No.3 respectively, are currently under construction. Other planned sites include: parts of the Hollandse Kust (west), Ijmuiden Ver, Nederwiek, Ten noorden van de Waddeneilanden, and Doordewind (Government of the Netherlands, 2021). In Table 2.1, the aforementioned planned wind farm developments are presented in detail. Please note that the tender dates for the scheduled wind farm zones (*) are indicative, as the final scheduling decisions will be made in 2024 (Government of the Netherlands, 2021).

Table 2.1: Offshore wind farm sites planning and tender scheduling (Government of the Netherlands, 2021)

Capacity (GW)	Offshore Wind Site	Tender for sites	Expected commissioning date
0.75	Borssele, Sites I and II	Implemented in 2016	2020
0.75	Borssele, Sites III, IV en V	Implemented in 2016	2020
0.76	Hollandse Kust (zuid), S. I&II	Implemented in 2017	2022-2023
0.76	Hollandse Kust (zuid), S. III& IV	Implemented in 2019	2022-2023
0.76	Hollandse Kust (noord), Site V	Implemented in 2020	2023
approx. 0.7	Hollandse Kust (west), S. VI	Implemented in 2022	2025-2026
approx. 0.7	Hollandse Kust (west), S. VII	Implemented in 2022	2025-2026
approx. 1	IJmuiden Ver, Site III	4th Q 2023	2028
approx. 1	IJmuiden Ver, Site IV	4th Q 2023	2028
approx. 1	IJmuiden Ver, Site I	4th Q 2023	2029
approx. 1	IJmuiden Ver, Site II	4th Q 2023	2029
approx. 1	IJmuiden Ver, (noord), Site V	2nd Q 2025	2029
approx. 1	IJmuiden Ver, (noord), S. VI	2nd Q 2025	2029
approx. 2.0	Nederwiek (zuid), Site I	2nd Q 2025	2029
approx. 2.0	Nederwiek (noord), Site II	2026*	2030
approx. 2.0	Nederwiek (noord), Site III	2026*	2031
approx. 0.7	Hollandse Kust (west), S. VII	2026/2027*	TBD*
approx. 0.7	Ten noorden van de Waddeneilanden, Site I	2026/2027*	2031
approx. 2.0	Doordewind, Site I	2027*	2031
approx. 2.0	Doordewind, Site II	2027*	2031

The Dutch energy ministry recently designated some new areas in the North Sea for offshore wind energy production. As can be seen on the map of Figure 2.3, the search areas spread across the Dutch shelf of the North Sea, and together they represent 10.7 GW of wind energy (Rijksoverheid, 2022b).

Figure 2.3: Designated wind energy areas in the Dutch self of the North Sea (Rijksoverheid, 2022b)

These search areas are currently planned to be commissioned shortly after 2030. Adding the new search areas to the already existing ones will double Netherlands' offshore wind power capacity, reaching around 21 GW by 2030 (Rijksoverheid, 2022b). These wind areas, however, are planned to be interconnected to land by electricity cables (and not pipelines), with the necessary procedures to realize that connection having already started (Guidehouse & Berenschot, 2021; Rijksoverheid, 2022b). Regarding the energy transport in the form of hydrogen via pipelines in the North Sea, this is planned to take place post 2030, with a 500 MW demonstration project already announced (Neptune Energy, 2022c). However, this timetable needs to be further accelerated, since the REPowerEU package demands increased green hydrogen production in the EU.

Nevertheless, the Dutch Government is already planning the energy roadmap to 2040, considering potential offshore hydrogen production applications. Specifically, in the 'Program North Sea 2022-2027' document, which is part of the National Water Program 2022-2027, offshore hydrogen production is mentioned as an option to utilize offshore wind energy from new search areas and transport it to the shore. These developments are currently planned to move forward after 2030, following a substantial further growth of offshore wind energy. In particular, new search areas are planned to be utilized for wind farms accommodation, as can be seen in the map of Figure 2.4. These new search areas provide a total space for approximately 34 GW of offshore wind (Ministerie van Infrastructuur, 2021).

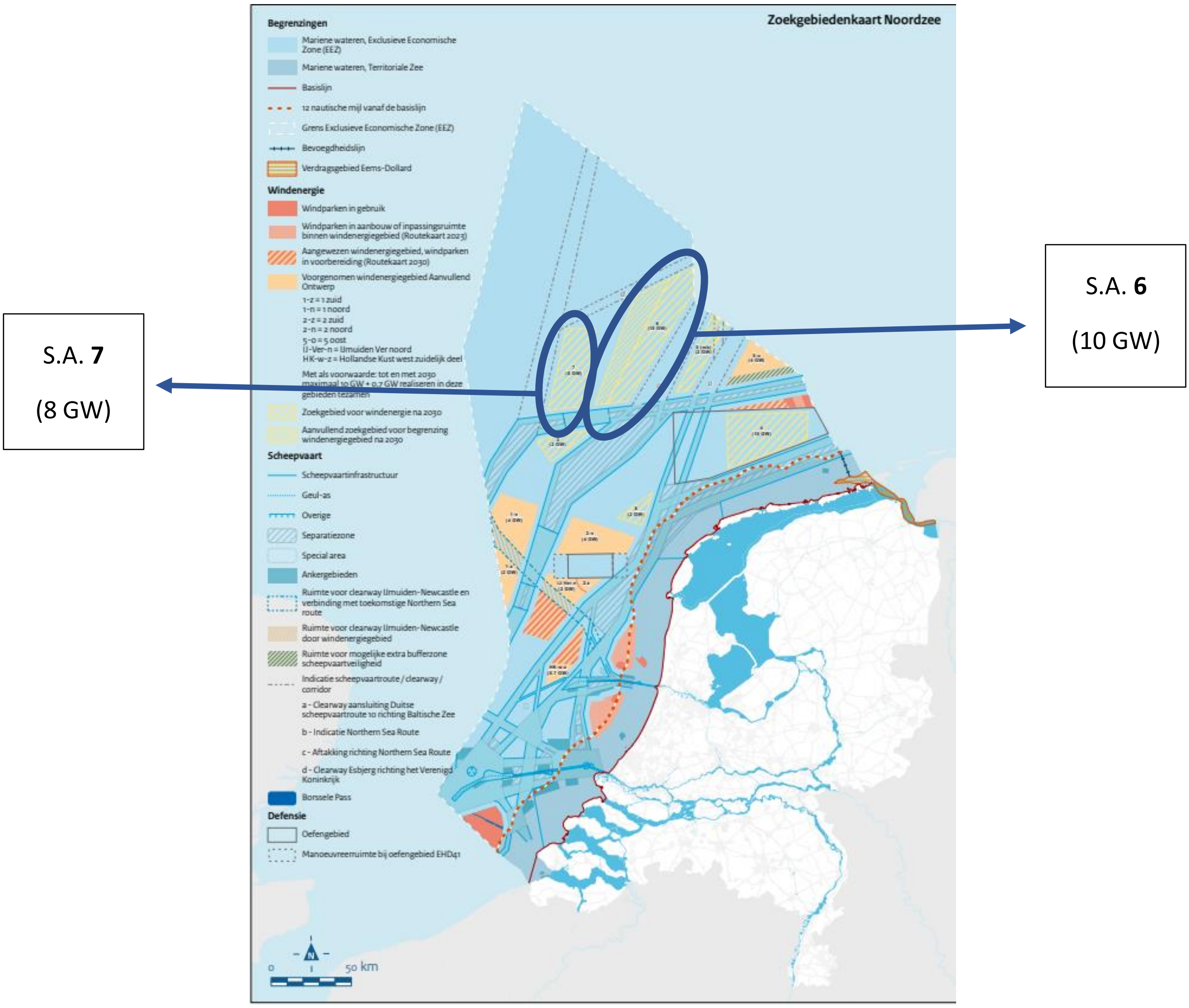

Figure 2.4: Offshore wind search areas in the Dutch self of the North Sea, including post 2030 plans (Ministerie van Infrastructuur, 2021)

Specifically, some of the search areas are of particular interest to this project since existing gas pipelines are already close by. These pipelines could be utilized for the hydrogen transportation to the shore, without the need for extensive new infrastructure development, thus bringing the overall cost down. According to the Dutch Ministry of Infrastructure, search areas 6 and 7 (Figure 2.4) could be utilized for offshore hydrogen production. Both search areas are being investigated for energy hub development possibilities, as well as for energy transport via hydrogen. Existing gas infrastructure will also be assessed to evaluate whether the search areas can be utilized to reduce the spatial and ecological impact (Ministerie van Infrastructuur, 2021). Specifically, NOGAT pipeline crosses search area 6 and NGT pipeline is located very close to the SW part of search area 7.

In September 2022 the Dutch Government established new targets for offshore wind development, i.e., 50 GW in 2040 and 70 GW in 2050 (Ministerie van Economische Zaken en Klimaat, 2022). As can be seen in the map of Figure 2.4, some of the areas currently considered for this purpose are depicted with a light green colour. Adding up the spatial footprint of these search areas, they can count up to a total capacity of approximately 34 GW, meaning that additional space needs to be freed up in the

North Sea for the offshore wind targets to be achieved. In Table 2.2 details on the aforementioned search areas can be found (projected capacities, remarks). The division of the capacity and allocation to each search area was done based on the assumption that all wind energy will be transmitted to the shore in the form of electricity. However, this does not mean that options such as offshore electrolysis with hydrogen transmission to shore will be ruled out. A more elaborate description of these search areas can be found in the report prepared by Guidehouse and Berenschot for the Netherlands Enterprise Agency (Guidehouse & Berenschot, 2021).

Table 2.2: Search Areas, Capacities, and attention points (Guidehouse & Berenschot, 2021; Rijksoverheid, 2022c)

Search Area #	Capacity (GW)	Comments
3	2	Relatively small search area. Potential to expand to 4 GW if connected to other search areas.
4	10	Overlap with military exercise area EHD42. Also shipping safety risk.
5 (mb)	2	Shipping safety risk.
5 (oost)	4	Nearby shipping routes – collision risk.
6	10	Maximum potential of 10-12 GW, if connected to search area 7 on the west. 8 GW are projected for partial development for 2040. Transport via molecular energy carriers (i.e., hydrogen) is investigated.
7	8	Maximum potential of 8 GW. 4 GW if connected to search area 6. Transport via molecular energy carriers (i.e., hydrogen) is also investigated.
8	2	Small area. High shipping safety risk.

2.3 Natural Gas Developments in the North Sea

Apart from harnessing the potential wind energy in the North Sea, it is necessary to also exploit the natural gas resources of the area, in order to realize diversification of gas supply and, thus, increase Europe's energy security. The North Sea contains numerous gas fields, allocated among the continental shelfs of Netherlands, Germany, Denmark, Norway, and the U.K. Even though many of those gas fields are on the verge of depletion, other newly explored fields are ready to be exploited. Such example is the gas field in block N05 close to the Dutch-German border (RHDHV, 2020). As can be seen in Figure 2.5, the existing offshore natural gas pipelines in the North Sea form a vast network, connecting offshore gas fields with the shores of the surrounding countries. A great number of those pipelines are eligible for being repurposed for hydrogen transportation in the coming decades, creating the potential for the North Sea to be converted into a hydrogen transport network. For instance, the oil and gas authority of the UK has already pinpointed one hundred existing natural gas pipelines in the UK's continental shelf that are suitable for repurposing for hydrogen transportation (Harley, 2022).

Figure 2.5: Existing natural gas pipeline network in the North Sea (Entsog, 2021)

Regarding the depletion date of the natural gas fields in the North Sea, most fields are expected to stop producing between 2026 and 2030, according to input provided by NGT (R. Hagen, M. Ros, personal communication, April 12, 2022). However, some gas fields are planned to continue production post 2030, for example the Ameland Westgat (AWG) gas field. The gas fields depletion dates coincide with the proposed timeline of this study, facilitating the repurposing of gas pipelines into hydrogen by 2030. The gas fields which are expected to continue production post 2030 are also planned to be facilitated by rerouting the produced gas to neighboring pipelines, as will be explained in detail in Section 2.4.

The target of this study is to realize simultaneous transmission of both hydrogen and natural gas, through different transmission pathways. Therefore, it is necessary to figure out a system configuration which will include existing pipelines within the Dutch continental shelf (suitable for repurposing into hydrogen transmission pipelines) as well as newly explored gas fields. Given that the North Sea's existing pipeline network is massive, there is a need for narrowing down to the most suitable potential system configurations for this case study, as will be analysed in the following section.

2.4 Scenarios for Parallel Hydrogen & Natural Gas Transportation

Various different possible configurations could be proposed for the parallel hydrogen and natural gas transmission to the Dutch shore, however the system examined in this study is the NGT - NOGAT pipeline network. These gas pipelines are located extremely close and, in some cases, even overlap with future offshore wind search areas, which could be developed for offshore hydrogen production. Specifically, as can be seen in Figure 2.6, the NGT pipeline is located near search areas 7, 3, 8, 4, and 5, whereas the NOGAT pipeline also crosses search area 6 and is located next to search area 5mb. The NGT and NOGAT pipelines could also facilitate natural gas transportation from existing gas fields (e.g., L10, Ameland Westgat) as well as from newly explored ones (e.g., N05-A). More details on the NGT and NOGAT pipelines can be found below.

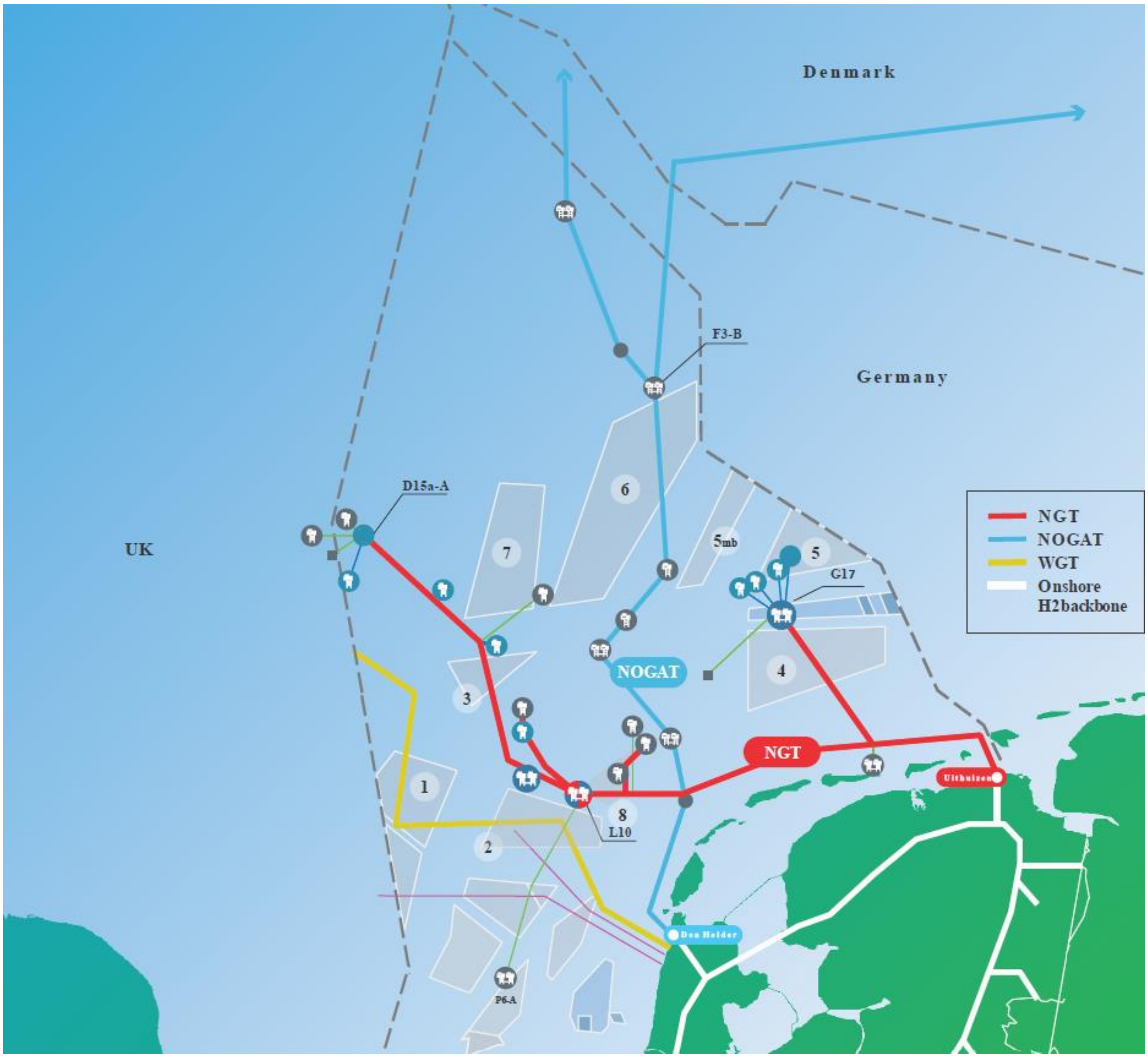

Figure 2.6: Existing natural gas pipelines in the Dutch continental shelf. Special focus on: NGT and NOGAT pipelines and designated offshore wind search areas (Noordgastransport, 2022; Northern Offshore Gas Transport, 2022)

➢ NGT:

Currently, the NGT (Noordgastransport) pipeline network is being used to transport natural gas from fields located in the Dutch continental shelf (and even further) to the Uithuizen processing facility in the northern part of the Netherlands, covering approximately 470 km in total (Neptune Energy, 2022b). The NGT pipeline network can be clearly seen in the map of Figure 2.6 (red colour). This pipeline network has been operational since 1975, transporting significant amounts of natural gas (capacity: 42 mil Nm^3/d) and is managed and operated by NGT (Neptune Energy, 2022a).

Regarding the future of the NGT pipeline network, its operators indicate that it is all set to facilitate the energy transition. Specifically, DNV-GL as well as Bureau Veritas have conducted studies for NGT and its potential to be retrofitted for hydrogen transmission, concluding that there are no showstoppers for achieving that (NGT, 2022). In fact, in October 2022, NGT acquired official certification for the entire network for being suited for the safe and reliable transport of hydrogen for 40 years (Bureau Veritas, 2022). That way, NGT can become part of an offshore hydrogen backbone, ready to transmit offshore produced hydrogen (from offshore wind farms) to the Dutch shore, and even get connected to the onshore hydrogen backbone. According to the NGT operators, this dedicated H_2 infrastructure is planned to be operational in 2030 (approx.) and will be capable of accommodating around 10-14 GW of offshore wind (NGT, 2022). This way, NGT can facilitate the energy transition towards decarbonisation and offer a less expensive solution than installing new electricity cables to transport the offshore wind energy to the shore, especially in the case of production taking place further offshore (NGT, 2022).

The way NGT has been operating throughout the years is by being an open-access natural gas transmission network, providing equal opportunities to all operators who needed transportation services from a linked site in the North Sea to Uithuizen. Future plans for the NGT pipeline network will include the same approach for transporting hydrogen (produced offshore) to the Dutch shore, guaranteeing a fair treatment to all offshore wind farm operators who are converting offshore wind electricity into H_2 (NGT, 2022). NGT tries to consolidate their position in the offshore hydrogen transportation scene, by being involved in numerous relevant projects and consortia (e.g., PosHYdon, North Sea Energy, H_2opZee, AquaVentus, and others) exploring the offshore hydrogen potential in action (NGT, 2022). Technical characteristics of the NGT pipelines can be found in Figure 2.7.

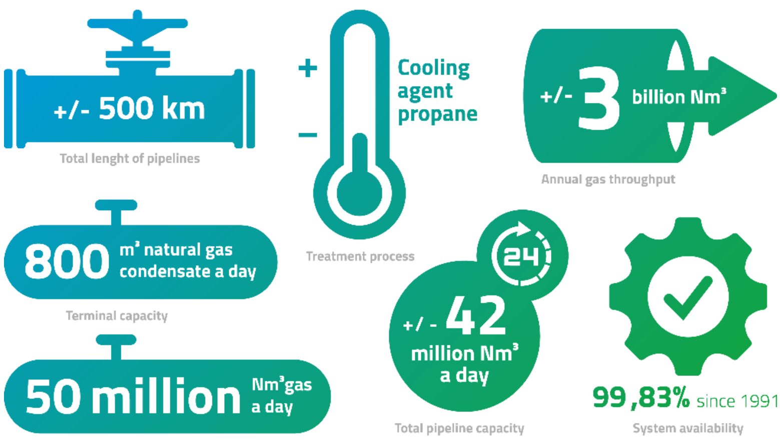

Figure 2.7: NGT technical specifications (facts & figures) schematic summary (NGT, 2022)

➢ **NOGAT**:

Currently the NOGAT (Northern Offshore Gas Transport) subsea pipeline network is transporting natural gas, linking the Dutch continental shelf (and beyond) to the onshore gas processing facility in Den Helder, northern Netherlands. The NOGAT pipeline network has a total length of around 264 km, and has been in use since 1992 (NOGAT, 2022). Apart from the Dutch continental shelf, the NOGAT pipeline network also stretches to the Danish and German continental shelfs, through the Tyra West – F3 pipeline (length: 100 km) and A6 – F3 pipeline (length: 118 km) respectively (NOGAT, 2022). In the map of Figure 2.8 the NOGAT pipeline system can be seen, along with the connections to Denmark and Germany. Similar to the NGT pipeline network, NOGAT is also managed and operated by Neptune Energy (Neptune Energy, 2022a). Figure 2.8 presents the basic characteristics of the NOGAT pipeline. It should be noted that, similar to NGT, NOGAT also acquired an official certificate for the safe and reliable transport of hydrogen via its network for 40 years (Bureau Veritas, 2022).

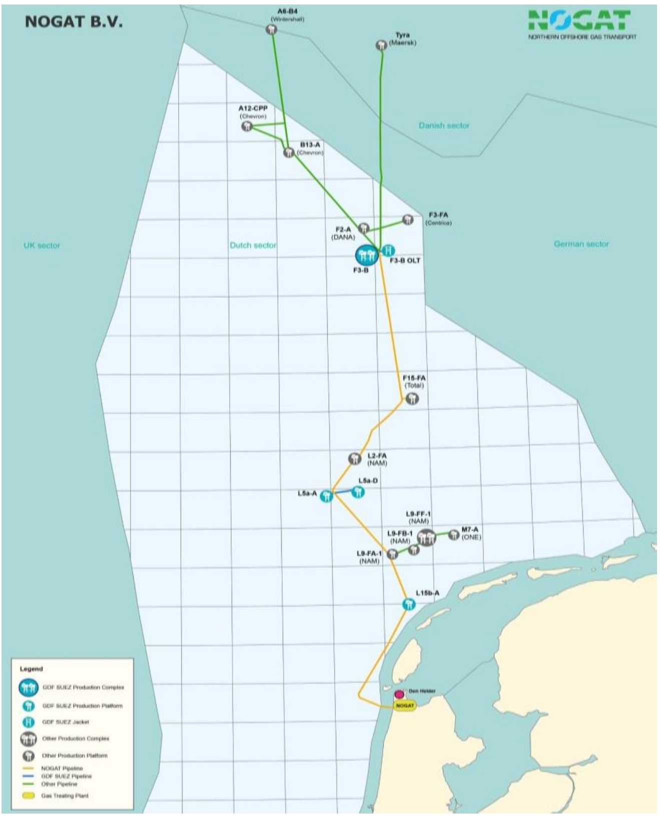

Figure 2.8: Map of the NOGAT pipeline network in the Dutch continental shelf including the connections to Germany and Denmark (NOGAT, 2014)

Table 2.3: Basic technical characteristics of the NOGAT pipeline (NOGAT, 2022)

Total Length of Pipelines	+/- 264 km
Total Pipeline Capacity	+/- 32 million Nm^3/d
Gas Throughput	+/- 3.6 billion Nm^3/y
Terminal Capacity	Treatment: 36 million Nm^3/d

In order for parallel transmission of hydrogen and natural gas to be achieved in the Dutch continental shelf in the North Sea, numerous different scenarios could be explored, examining various potential transmission paths. The NGT and NOGAT pipelines are capable of transporting both hydrogen and natural gas to the Dutch shore and are located near offshore wind search areas, making them prime candidates for facilitating this parallel transmission. The scenario selection is based on the development potential of each wind search area, the expected realization timeline, as well as the associated cost of developing offshore infrastructure (e.g., new pipelines, connectors). After considering various potential scenarios including the NGT and NOGAT pipelines as the main hydrogen and natural gas transport facilitators, the two most suitable scenarios are presented in Sections 2.4.1 and 2.4.2.

For the purpose of this research study Quantum Geographic Information System (QGIS) software was used, in order to obtain detailed geospatial information for the pipelines, the offshore wind search areas, and the offshore natural gas fields in the North Sea.

2.4.1 Scenario A

The configuration of the pipeline system in scenario A includes 100% hydrogen transmission through the NGT pipeline and rerouting natural gas to the NOGAT pipeline. The basis for developing scenario A is the potential for offshore hydrogen production at search areas 7 and 3 after 2030. Search area 7 has a potential of 8 GW of offshore wind capacity and search area 3 has potential for developing 2 GW offshore wind, and there are discussions about realizing offshore electrolysis for hydrogen production (Rijksoverheid, 2022c). In order for the NGT to be freed up for 100% hydrogen transportation, gas production from blocks D12, D15 needs to stop, which is possible given the scenario's timeline (2030). Hydrogen produced from search areas 7 and 3 (either from centralized electrolysis on a platform/ energy island, or from decentralized electrolysis taking place in-turbine) will then be fed to the NGT pipeline via new connections close to blocks E17 and K02 respectively. Hydrogen will then be transported all the way to the shore at Uithuizen.

To realize 100% hydrogen transmission via the NGT pipeline, some other considerations regarding natural gas need to be also taken into account. Specifically, apart from the gas fields in blocks D12 and D15, several other gas fields along NGT's trajectory need to be facilitated. The most significant ones are located in: L10, AWG, and N05. Gas field in block L10, which is one of the most important ones in the Dutch continental shelf, could continue being exploited until its depletion, and the gas being diverted to the NOGAT pipeline through a new pipeline connection in block L08. Another important gas field that is currently connected to NGT and needs to be redirected to NOGAT is the AWG field, located on the north-eastern side of Ameland island. The solution could be given by redirecting the gas from AWG to the North Branch of NGT (bypassing NGT) towards block G17. The North Branch should be disconnected from the NGT pipeline. A new connection could be established to link block G17 to the NOGAT pipeline, since the distance separating them is relatively small, to redirect the natural gas to NOGAT. Last but not least, newly explored gas field N05-A needs to also be considered, as production will begin within the next years. To take advantage of this new gas field and, thus, increase the region's energy security, N05 should be connected to the North Branch of NGT, via new infrastructure. Ultimately, all the natural gas produced in AWG and N05 should be redirected to NOGAT via the new G17-NOGAT connection and transported to the shore at Callantsoog. The transmission details according to scenario A are also summarized in Table 2.4.

Table 2.4: Summarized per field transportation arrangement, according to scenario A

Block	Details
D12	Natural gas production is halted
D15	Natural gas production is halted
E17	Connection of search area 7 (8 GW) with NGT
K02	Connection of search area 3 (2 GW) with NGT
L10	Natural gas production continues
L08	New pipeline connection between L10 and NOGAT. Redirection of natural gas produced at L10 to NOGAT
M09	AWG gas field continues natural gas production. Redirection of natural gas to the north branch of NGT (connecting M09 to G17) – Disconnection of the north branch from the main NGT line
N05	New pipeline connection between N05-A and the north branch of NGT
G17	New pipeline connection between G17 (north branch of NGT) and NOGAT. Natural gas from AWG and N05-A: Redirected to NOGAT

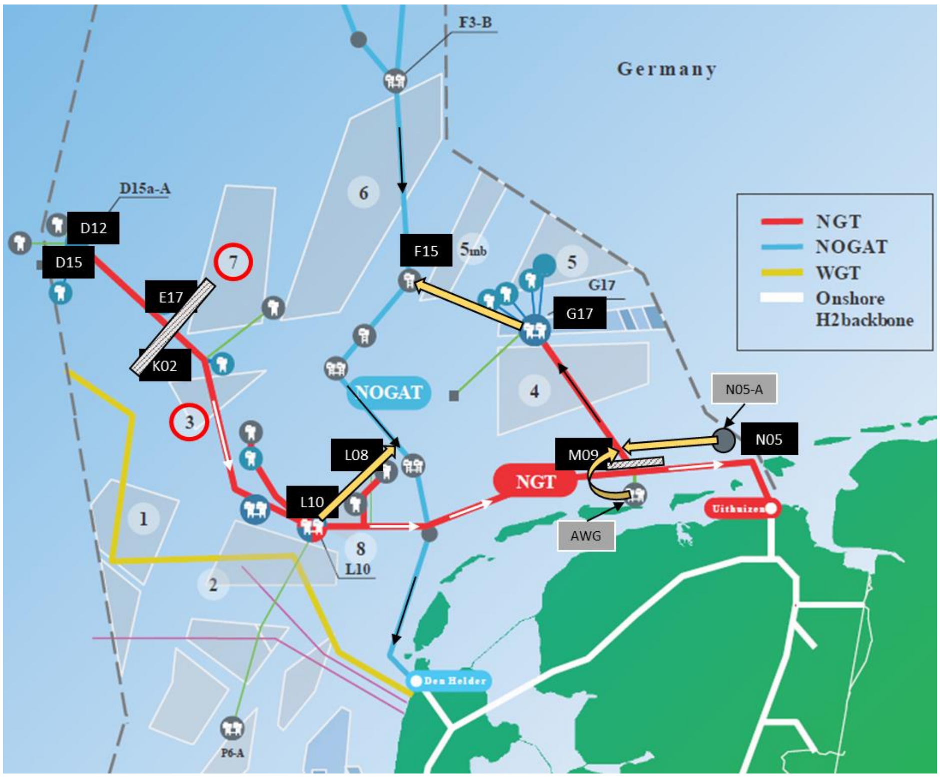

Figure 2.9: Detailed map of the NGT and NOGAT pipelines in the Dutch continental shelf, including the associated offshore wind search areas, North Sea blocks, associated gas fields, new proposed pipeline connections, and hydrogen & natural gas flows, according to Scenario A.

The proposed configuration for Scenario A can be also seen in the map of Figure 2.9, including the associated offshore wind search areas, associated gas fields, and the new connections proposed. As can be seen, the yellow arrows represent the new pipeline connections, the white and black arrows represent the hydrogen and natural gas flow respectively, and the white blocks represent the disconnection points. The black blocks represent the blocks of the Dutch continental shelf, and the grey circles are the associated gas fields.

2.4.2 Scenario B

The configuration described in scenario B concerns primarily the utilization of search areas 5 and 4 for offshore hydrogen production. The planned capacities for these search areas are 4 GW and 10 GW respectively. The reason behind examining this scenario is that the North Branch of NGT is located very close to search area 5 and crosses search area 4 and could be repurposed to realize hydrogen transmission to the shore (Uithuizen). This means that the eastern part of NGT (east of block M09), will carry offshore produced hydrogen from search areas 5 and 4 to Uithuizen, and the western part (west of M09) will carry natural gas towards the west (towards L10). This natural gas flowing towards the west will then be redirected to the NOGAT pipeline through a new connection in block L08, L12, or other, and be transported to the shore at Callantsoog. Another new connection that could be established, is between the gas field in block G17 and NOGAT at block F15. That way the G17 gas field can also be utilized until its depletion date and thus, further increase the region's energy security. By realizing scenario B, NGT is going to transport natural gas for a longer time period through its western part, until AWG and N05-A gas fields are depleted. When this is the case, the NGT pipeline could eventually also be freed up for hydrogen transmission. The transmission details according to scenario B are also summarized in Table 2.5.

Table 2.5: Summarized per field transportation arrangement, according to scenario B

Block	Details
G17	New connection between the north branch of NGT and search area 5 (4 GW)
M02	New connection between the north branch of NGT and search area 4 (10 GW)
M09	NGT pipeline divided in 2 parts: East (transporting H_2 coming from search areas 5 & 4 towards Uithuizen) and West (transporting natural gas towards NOGAT) AWG gas field continues natural gas production. Redirection of natural gas to the main NGT line (west of M09) towards L10 – Disconnection of the north branch from the main NGT line
N05	New connection between N05-A and West part of NGT. Natural gas transportation towards NOGAT pipeline
F15	New connection between gas fields located near G17 and the NOGAT pipeline. Redirection of natural gas to NOGAT
L08	New connection between the West part of NGT and NOGAT: Redirecting natural gas coming from AWG and N05-A to NOGAT (L12 could also be considered for such purpose)

The proposed configuration for Scenario B is also depicted in the map of Figure 2.10, including the associated offshore wind search areas, associated gas fields, and the new connections proposed. Similar to the map of Figure 2.9, the yellow arrows represent the new pipeline connections, the white and black arrows represent the hydrogen and natural gas flow respectively, and the white blocks represent the disconnection points. The black blocks represent the blocks of the Dutch continental shelf, and the grey circles are the associated gas fields.

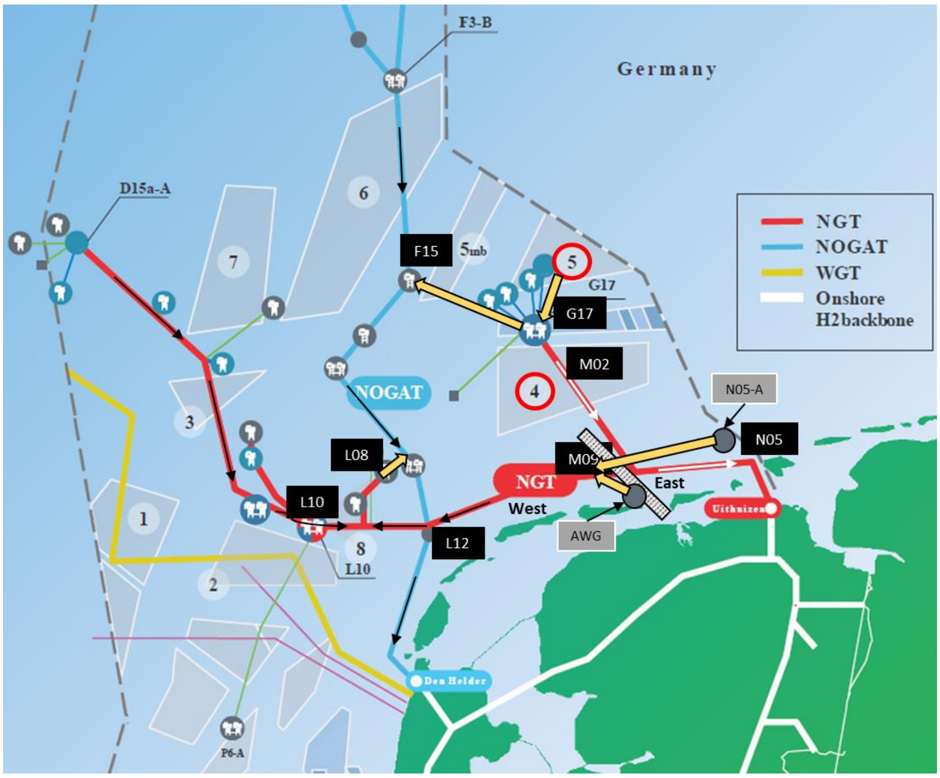

Figure 2.10: Detailed map of the NGT and NOGAT pipelines within the Dutch continental shelf, including the associated offshore wind search areas, North Sea blocks, associated gas fields, new proposed pipeline connections, and hydrogen & natural gas flows, according to Scenario B.

2.4.3 Scenario Selection: Proposed System Configuration

Overall, there could be numerous alternative scenarios regarding the system configuration for the parallel transport of hydrogen and natural gas, all of which need to be examined in great detail. Instead of the NGT pipeline being freed up for hydrogen transport, the case of transporting hydrogen via the NOGAT pipeline is also a realistic possibility. In fact, RVO; Guidehouse; Berenschot, (2021), in their study for the offshore wind integration between 2030 and 2040, suggested that connecting offshore wind search area 6 with the NOGAT pipeline would be an especially interesting option for transporting offshore produced hydrogen to the shore. They highlight the proximity of the NOGAT pipeline to search area 6 (NOGAT pipeline crosses search area 6 – therefore no major new infrastructure required for establishing a connection), as well as its significant capacity (Guidehouse & Berenschot, 2021).

However, in the present study hydrogen transportation via the NOGAT pipeline is not examined in great detail since it is not perceived to be a very realistic scenario under the current circumstances.

This scenario seems distant due to the northern branches of the pipeline, connecting the Dutch continental shelf with the Danish. Specifically, the Tyra West – F3 pipeline branch connects a very significant gas field of the Danish Sector of the North Sea, the Tyra gas field, to the NOGAT pipeline system and by extension to the Dutch shore. This creates a strong interdependence between the two countries since a large portion of Tyra field's natural gas is fed into the Dutch system. Tyra gas field is not expected to halt gas production soon (at least for the coming decades), following Europe's strategy of becoming independent from Russian fossil fuels. In fact, Tyra gas field is currently undergoing redevelopment, led by TotalEnergies, in order to further increase its output to 60,000 barrels of oil equivalent (boe) per day (TotalEnergies, 2022). Therefore, it is particularly challenging to make NOGAT available for 100% hydrogen transportation in the upcoming decades, without developing new infrastructure. On the other hand, making NGT available for 100% hydrogen transmission earlier than NOGAT constitutes a more logical solution in light of the current situation.

The realization of a scenario strongly depends on which offshore wind search areas area going to be prioritized and the method of energy transmission to the shore (via electricity or hydrogen). The newly assigned "search areas" that are included in North Sea Program 2022 – 2027, which focuses on the offshore developments in the North Sea (Rijksoverheid, 2022d), are mostly going to be developed with electricity infrastructure for the transmission of the energy to the shore. This is due to the relatively short distance of most offshore search areas from the shore, which favours electrical interconnection. However, for search areas 6 and 7 the construction of electricity infrastructure is currently unprofitable or not very cost-effective, due to their long distance from the Dutch shore, and therefore other solutions, like energy transportation via molecules (hydrogen) seem to be more preferable (Rijksoverheid, 2022d).

To determine the most suitable scenario for the parallel hydrogen and natural gas transportation to the Dutch shore, a deeper analysis of the offshore wind search areas is needed Specifically, search area 5 affects an international shipping route and also borders with Germany, meaning that consultation and research together with Germany is necessary. The risk of incidents with negative consequences for the environment is considerable (Rijksoverheid, 2022d). Another bottleneck for implementing Scenario B would be the overlapping between search area 4 and EHD42, a military exercise site. Relocation of EHD42 has not been possible. Possibilities of combined use require research that cannot be completed in time for a decision on the realization of a wind farm (Rijksoverheid, 2022d). Furthermore, search area 4 is located relatively close to the shore, so an electrical interconnection would make more sense than energy transmission via hydrogen from a techno-economic perspective. Therefore, the future utilisation of search area 4 remains unclear.

Summarizing, the approach used for selecting the most suitable scenario for the present case study mainly comes down to the development potential of each search area, the expected timeline for its realization, as well as the distance of each one from the shore, which would determine if energy will be transmitted via HVDC cables or by hydrogen molecules through pipelines. By transporting energy in the form of electricity via cables for the offshore wind search areas closer to the shore, and at the same time transporting hydrogen produced offshore via repurposed gas pipelines to connect the more distant ones, we could achieve the best of both worlds: Having green electricity for replacing the coal-fired plants, and at the same time kick-starting and accelerating a hydrogen market.

Due to the aforementioned reasons, the configuration described in **Scenario A** is selected over the one in Scenario B, as utilizing search areas 7 and 3 for hydrogen production, repurposing the NGT pipeline for 100% hydrogen transportation, and rerouting natural gas to the NOGAT pipeline is the most feasible and realistic option under the current circumstances. It should be noted that only Scenario A was analysed in-depth in this study, from a technical and economic standpoint, and more specifically the hydrogen transportation via the repurposed NGT pipeline.

NGT Pipeline Geographical Configuration: Hydrogen Transport

The total length of the NGT main pipeline (excluding branches) is found to be 318.2 km, using QGIS software for distance measuring. This length is measured from the gas platform in block D15 until the ending point in Uithuizen. However, the part of the NGT pipeline that is going to be used for hydrogen transportation corresponds to a smaller length: 253.2 km, since the measurement starts from search area 7 instead of block D15, as can be seen in the map of Figure 2.11. The individual lengths along the NGT pipeline, as measured with QGIS, are presented in Table 2.6. The platform of block L10 is used as an intermediary reference point, which could host a recompression unit if necessary.

Table 2.6: NGT pipeline: Individual parts length

Total NGT (main line)	318.2	km
D15 – L10	140.6	km
L10 – Uithuizen	177.6	km
D15 - S.A.7	65.0	km
S.A.7 – L10	75.6	km
S.A.7 – Uithuizen	**253.2**	**km**

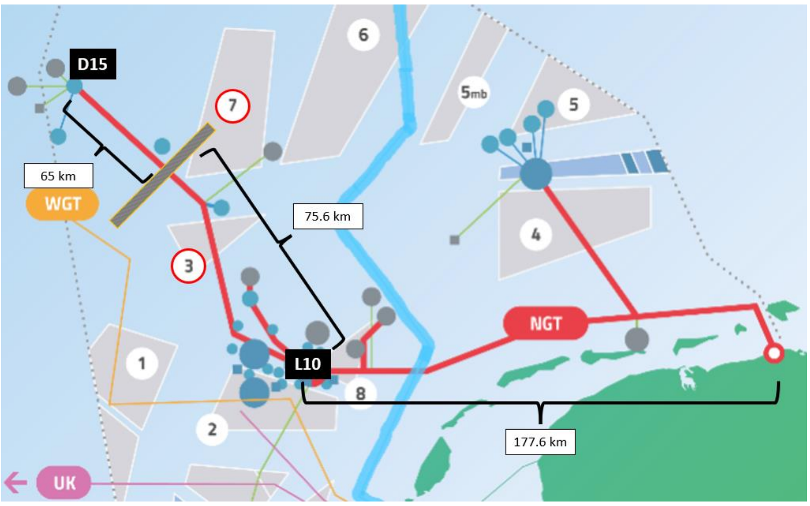

Figure 2.11: Map of the NGT pipeline including individual lengths, and associated platforms (D15, L10)

2.5 Connection Points

As analyzed in the previous sections, several connection points along the NGT and NOGAT pipelines need to be established in order to connect existing and new pipelines. These connections constitute a major part of developing the different transportation paths and could be achieved by using different technologies.

According to information obtained from interviews with NGT and Neptune Energy, one option would be using the existing t-piece connectors that are already preinstalled along the NGT and NOGAT pipelines. However, using t-piece connectors could be a relatively expensive option. Since the t-piece connectors' position is fixed, it might not always be convenient to use for connecting new pipeline sections to the main lines. The cost of installing a new t-piece connector in a suitable location, if there is not one available nearby, could reach €5 million. However, using a preinstalled t-piece connector could also reach the same cost level. Usually those are covered with boulders and other potential obstacles which could obstruct the connection procedure. In order for the connection to be established, the boulders need to be lifted, and a projection dome needs to be built. These, in addition to achieving the actual connection, requiring specialized divers to perform the underwater welding, make using preinstalled t-piece connectors quite labor intensive, and hence expensive.

An alternative would be using recently developed hot tap tee clamps. These pieces of mechanical equipment operate by clamping the existing pipeline, creating a sealed environment (elastomeric or graphite material is typically used), and then drilling into the pipeline (Connector Subsea Solutions, 2022). Afterwards, the new pipeline can be safely connected to the side of the clamp. The Hot Tap Tee Clamp (left), as well as the clamping procedure (right) are illustrated in Figure 2.12. Using this technology for establishing new connections along the NGT and NOGAT pipelines could potentially reduce the connecting cost, since it is much less labor intensive and does not require difficult and expensive underwater procedures, such as welding or building a dome. It should be highlighted that the above-mentioned information is based on interviews with NGT and NOGAT pipeline operators (R. Hagen, M. Ros, personal communication, October 11, 2022).

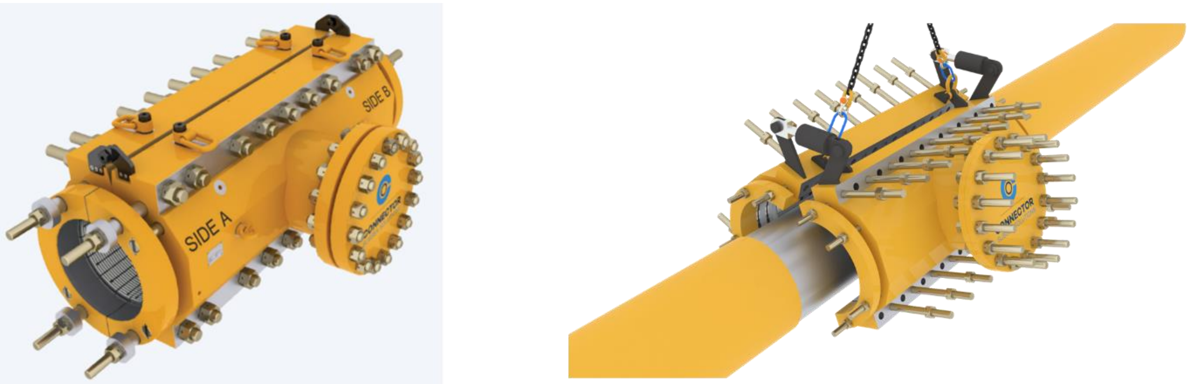

Figure 2.12: Hot Tap Tee Clamp developed by Connector Subsea Solutions (left) – Clamping procedure on a pipeline section (right) (Connector Subsea Solutions, 2022)

3

Physical Configuration of the System

Having determined the geographical layout of the system, this chapter will discuss its physical configuration, analysing its components, their function, and their interconnections. The focus will be on the NGT pipeline, which according to the selected Scenario A will be transporting hydrogen produced offshore, utilizing electricity from offshore wind search areas 7 and 3.

3.1 Offshore Hydrogen Production

Producing green hydrogen at minimal cost can be achieved in locations with abundant renewable energy resources, mainly solar or wind. As analysed in the previous chapter, the hydrogen production for the present study will take place offshore via electrolysis of water, which will be powered by the offshore wind turbines of search areas 7 and 3. Being located at a large distance from the Dutch shore, the most cost effective option for transmitting the energy produced would be by converting it to hydrogen (at the energy production site) and transporting that via pipelines, as it is more economical than transmitting electricity to the shore and converting it to hydrogen there (Groenemans et al., 2022; van Wijk, 2021b). For such a large-scale hydrogen production system, the electrolyzer design, placement and engineering are of great importance. Contrary to the energy transport via HVDC electricity cables (common for offshore wind farms located relatively close to the shore) which would require a convertor station for converting the generated electricity to HVDC electricity, in this case an electrolyzer facility is required to transform the generated power into hydrogen (van Wijk, 2021b).

The production of green hydrogen will be achieved with offshore electrolysis (direct coupling of offshore wind turbines and electrolysis systems), since it is economically advantageous compared to transmitting electricity to the shore and producing hydrogen there (Groenemans et al., 2022). According to Guidehouse & Berenschot (2021), the expected timeline for GW-scale offshore electrolysis projects is estimated to be around 2027-2035, as can be seen in Figure 3.1.Economically optimal offshore electrolysis requires sufficient demand for green hydrogen and adequate renewable electricity generation and can be realized through two different methods: centralized and integrated (de-centralized). Centralized electrolysis entails building an electrolysis plant on an offshore platform or an energy island (artificial island, specifically developed to accommodate the electrolysis process), and connecting it to the wind turbines through electricity cables. On the other hand, integrated (or de-centralized) implies that the electrolysis unit is built into the wind turbine and is located on the tower, foundations, or the nacelle of the wind turbine (Guidehouse & Berenschot, 2021).

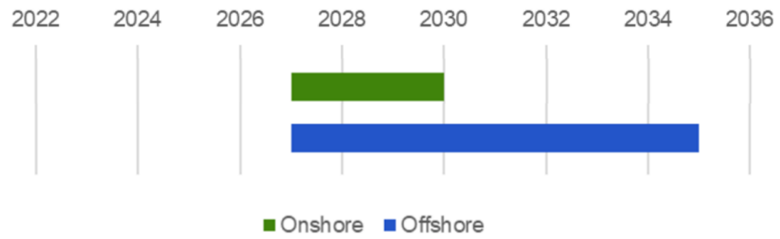

Figure 3.1: Expected timeline for GW-scale electrolysis projects (Guidehouse & Berenschot, 2021)

3.1.1 Offshore Electrolysis: Centralized vs Integrated

Presently, centralized offshore electrolysis seems to be more mature than its decentralized counterpart, due to two primary reasons: First of all, the offshore sector has vast expertise with offshore platforms (dating back to 1900s with offshore oil and gas platform development). Second, the wind farm structures and the wind turbines themselves require no modifications. Furthermore, centralized offshore electrolysis in energy hubs or islands could be an advantageous option in 2030s for establishing a hybrid connection (electricity and hydrogen) and, potentially, cross-country interconnection. However, a downside of centralized offshore electrolysis, when using offshore platforms, is that sizable wind farms may require numerous electrolysis platforms, introducing a significant additional expense. Spatial issues due to the large footprint of electrolyzers when significant amounts of hydrogen are being produced could be resolved by using energy islands to accommodate those, instead of employing offshore platforms. Nevertheless, centralized solutions like energy islands are not proposed for this case study, as they include significant cost additions. Apart from that, developing an artificial energy island from scratch requires a significant time period. Thus, good planning is required (energy island development beginning: approximately 10 years before the initial operating phase) (Guidehouse & Berenschot, 2021).

Integrated electrolysis on the offshore wind turbines (also known as in-turbine electrolysis) could be an interesting option for the present study, as it provides a number of benefits over centralized electrolysis. First of all, there is no need for large electrolysis platforms on island or hubs, which reduces the overall infrastructure cost. Additionally, a wind farm's design could be optimized for producing hydrogen by water electrolysis, thus eliminating some electricity chain transformation steps between the electrolyzer and the wind turbine. Integrating the whole sequence from the electricity generator to the electrolyzer stack, enables the disposal of several electrical components, hence decreasing both the associated electrical losses (5-10%) and the overall capital expenses (Guidehouse & Berenschot, 2021). For example, there is no need for an AC/DC/AC converter but only for an AC/DC, since the DC electricity can be directly fed into the electrolyzer. On the other hand, a disadvantage of in-turbine electrolysis compared to centralized is that it is currently not favourable to hybrid connections, which allow for hydrogen and electricity transmission to happen simultaneously.

Integrating electrolysis into the wind turbine units also brings ramifications for the infrastructure needed. Specifically, since the output of each wind turbine will be hydrogen and not electricity, the turbines must be linked to a central platform for the compression and gas treatment steps before being fed to the main pipeline. This connection is achieved through 'inter-array' (also referred to as infield) pipelines. The central platform is then linked to the main pipeline system so that hydrogen can be transported to the shore. The concept of infield pipelines, as well as compression will be analysed in Section 3.3 of this report.

3.1.2 In-turbine Offshore Electrolysis

After comparing the two offshore electrolysis methods in the previous section, the selection of the most suitable one for this case study is based on the following arguments: In-turbine electrolysis is a more cost-effective option compared to centralized electrolysis due to the fewer steps required in the process, infield pipelines connecting the turbines are less expensive than new electricity cables for the same purpose, and the number of components needed is decreased, resulting in lower capital expenditures. The latter also indicates that integrated electrolysis reduces the required overall footprint that would be required for a centralized solution, like platforms or an energy island. The main disadvantage for selecting in-turbine electrolysis is that the technology is less mature than centralized at the moment. However, it is expected to mature and be ready for implementation by the time this project is initiated (around 2030). Based on this analysis it is concluded that in-turbine electrolysis is the most suitable solution for producing hydrogen offshore in the present case study.

Figure 3.2: Integrated in-turbine electrolysis unit, installed in the tower of the wind turbine (Image credit: Siemens Gamesa)

➢ Siemens Gamesa SG 14 – 222 DD with Integrated In-turbine Electrolysis

One of the pioneers in the in-turbine electrolysis sector is Siemens Gamesa, having already taken important steps towards the direction of implementation of this technology. The wind turbine manufacturer has been exploring ways to integrate electrolyzer units in their offshore wind turbines for direct green hydrogen production. More specifically, as Siemens Gamesa and Siemens Energy announced in 2021, they will be investing about 120 million euros over the course of 5 years for the development of a fully integrated wind-to-hydrogen solution: An offshore wind turbine with an integrated in-turbine electrolyzer, capable of operating as one system producing green hydrogen directly (Siemens Gamesa, 2021). By 2025 or 2026 the two companies are planning on providing a full-scale presentation for their developed solution. This is expected to take place well ahead of the present project's timeline, which might mean some further cost reduction due to the technology's maturity after 2030. The plan is to seamlessly integrate an electrolysis unit (developed by Siemens Energy) in the SG 14 - 222 Direct Drive (DD) offshore wind turbine (developed by Siemens Gamesa), which is one of the most powerful offshore wind turbines in the market with a capacity of up to 15 MW (Siemens Gamesa, 2021, 2022). These particular wind turbines feature a rotor with a diameter of 222 meters and 108 meters of blade length, as can be seen in the technical specifications table below among other characteristics (Table 3.1). The SG 14 - 222 DD offshore wind turbine including the in-turbine electrolysis unit is depicted in the sketch of Figure 3.3.

Table 3.1: Technical Specifications of SG 14-222 DD (Siemens Gamesa, 2022)

IEC class	I, S
Nominal power	14 MW (Up to **15 MW**, using Siemens Power Boost function)
Rotor diameter	222 m
Blade length	108 m
Swept area	39,000 m²
Hub height	Site–specific
Power regulation	Pitch-regulated, variable speed

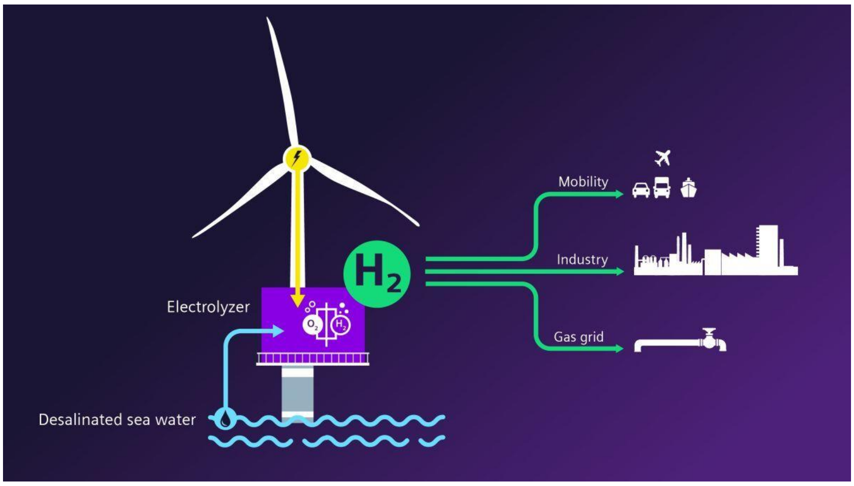

Figure 3.3: Integrated offshore in-turbine electrolysis unit and potential H_2 end uses (Siemens Gamesa, 2021)

3.1.3 Electrolysis Technology

Regarding the electrolysis system for the production of hydrogen, two technologies are mostly used in commercial projects due to their maturity: Alkaline and Proton Exchange Membrane (PEM) electrolyzers (Calado & Castro, 2021). Currently, alkaline electrolyzers are more mature and less expensive than PEM electrolyzers, having a lower CAPEX (Buttler & Spliethoff, 2017; IRENA, 2018). In fact, cost estimations for the two technologies, by 2030, result in approximately 400 €/kW for alkaline (Dickschas & Smolinka, 2019; Graré, 2019), and 500 €/kW for PEM electrolyzers (Buttler & Spliethoff, 2017; IRENA, 2020). Apart from lower cost, alkaline electrolyzers also have higher efficiencies and longer lifetime compared to PEM (Buttler & Spliethoff, 2017; Roobeek, 2020). On the other hand, PEM electrolyzers have the advantage of a lower spatial footprint compared to alkaline, as well as quicker response to fluctuations caused by renewable energy production (Ansar et al., 2019; Lichner, 2020; Zervas, 2021). However, for the present study, the response to fluctuations does not pose an issue, due to the inertia of the rotor mass, and the electrolyzer's footprint does not affect the technology selection, due to the adequate space inside the wind turbine tower. Specifically, the diameter of a 15 MW wind turbine tower is around 10 m, sufficient to host an in-turbine electrolyzer unit (Gaertner et al., 2020). Therefore, for this application, alkaline electrolyzer technology is proposed, due to its aforementioned advantages, being a cost-effective and mature solution. Nevertheless, it should be noted that the electrolyzer technology should be further investigated, since it is not in the direct scope of this study.

3.2 Hydrogen Compression – Compression Stations

Considering the present case study, after hydrogen is produced by in-turbine electrolysis, it needs to be transported to the shore in order to reach its end destination and be injected to the main hydrogen grid. This injection into the core onshore hydrogen backbone requires a pressure of no less than 50 bar, according to input provided by the Dutch gas TSO, Gasunie. Specifically, according to information obtained during an interview with Gasunie (W. van de Graaf, personal communication, October 19, 2022), the onshore hydrogen network will operate between 30 and 50 bar for an initial period. At a later stage, this operating range might be increased to 40-60 bar, in order to have slightly more capacity in the onshore transport system (compared to the 30-50 bar range). The reason for using an operating pressure range is that as hydrogen will be fed into the grid, large pressure drops will occur over the onshore system. In order to have a safety margin for these pressure drops, but also be able to balance the system by slightly adjusting the pressures, operating ranges need to be employed. For the initial phase of the onshore hydrogen network a 30-50 bar operating range is considered reasonable, although a 40-60 bar range would facilitate the increased long-term future capacity of the onshore hydrogen system. However, an increased pressure at the shore would result in increased compression costs, since this would either require a higher initial pressure, or an additional compression step (recompression) before hydrogen reaches the shore. A potential pressure increase would not affect the NGT pipeline, since it can handle pressures up to 136 bar, according to NGT (R. Hagen, M. Ros, personal communication, October 11, 2022).

In order for the hydrogen to reach the shore at a pressure of no less than 50 bar, it requires to be compressed near the production site. Since hydrogen is assumed to be coming out the in-turbine electrolyzer with a pressure of 30 bar (Brun & Allison, 2022; Roobeek, 2020; Zervas, 2021), the compression requirement needs to account for the remaining 20 bar, as well as for the expected pressure loss along the length of the pipeline, as will be explained in more detail in the coming chapters. This pressure boost is achieved by compressors, which are assumed to be located in compression stations near each wind farm. The hydrogen transportation from each wind turbine (decentralized electrolysis) to the compression stations will be analysed in Section 3.3.

3.2.1 Compressor Types

The most common type of compressors in use today are mechanical compressors. Mechanical compressors' operating principle is converting mechanical energy directly into gas energy (Sdanghi et al., 2019). There are various different types of mechanical compressors, however specifically for hydrogen compression the most commonly used ones are either dynamic or positive displacement compressors, as can be seen in the vertical tree diagram of Figure 3.4 (M. A. Khan et al., 2021). Apart from mechanical compressors, there are also non-mechanical compressors available, which offer many advantages compared to mechanical ones (e.g., reduced number of moving parts, smaller size). However, there still is no technological maturity since they are still in development stages and therefore, will not be further analysed in this study.

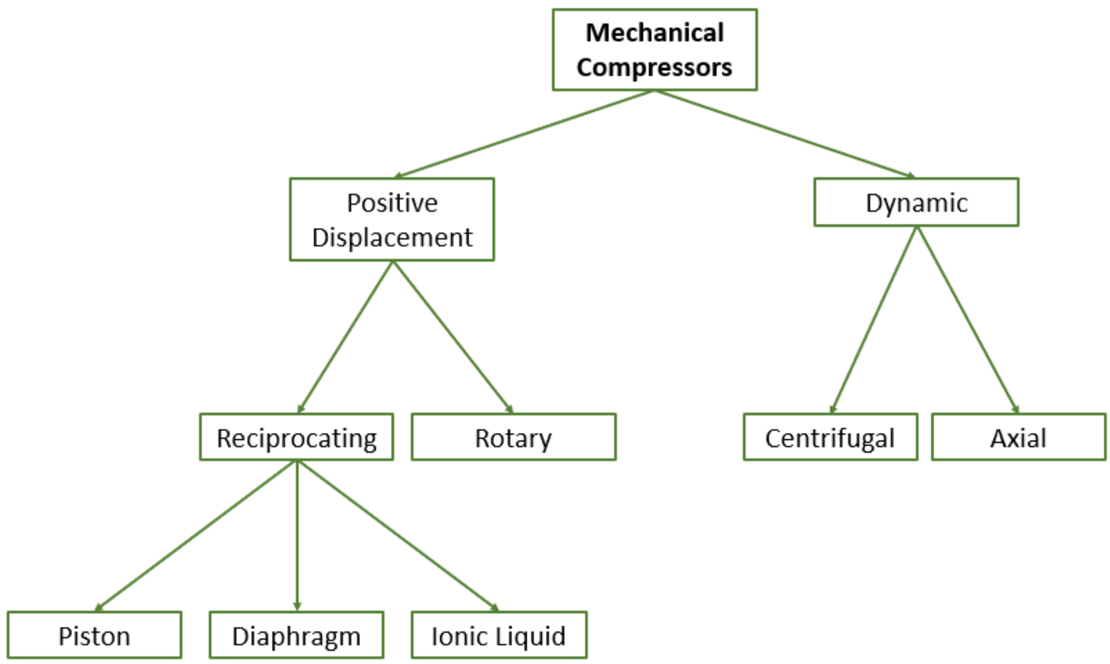

Figure 3.4: Classification of Mechanical Compressors (M. A. Khan et al., 2021)

The compression solutions that are more applicable to the present study will be analysed below, and a final selection will be made in Subsection 3.2.2, based on their characteristics. For more detailed information on more compressor types and their working principles, one can refer to the publications by Khan et al., (2021) and Sdanghi et al., (2019) on hydrogen compression technologies.

1. <u>Reciprocating Piston Compressors:</u>

One of the most used compressor types with a wide range of industrial applications are reciprocating piston compressors. Based on a positive displacement mechanism, reciprocating compressors are widely utilised for H_2 systems, ideally for levels of pressure of 30 bar or higher (Sdanghi et al., 2019). The operating principle of reciprocating compressors is based on a retrograde motion, by compressing and displacing the contained gas. As depicted in Figure 3.5, a single step reciprocating compressor's main components are: a piston (inside a cylinder), a crankshaft system, which drives the piston in a reciprocating movement via a connecting rod, and two valves incorporated on the cylinder: one for gas intake (suction valve) and one for gas delivery (discharge valve) (Sdanghi et al., 2019). The crankshaft transforms the rotational movement into linear, which is also known as a reciprocating movement. The required energy for the compression is provided to the system by a thermal or an electrical machine.

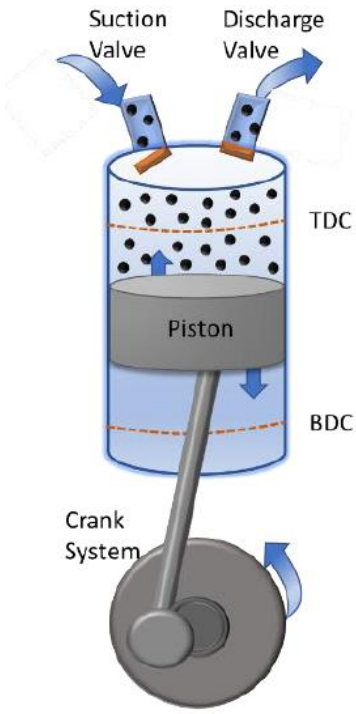

Figure 3.5: Depiction of a reciprocating compressor. TDC: Top dead centre; BDC: Bottom dead centre (Sdanghi et al., 2019)

Reciprocating compressors are capable of producing much higher outlet pressures as well (up to 850 bar), if combined in a multi-stage setting. However, this is not required for the present case study, since not that high pressures are needed for transporting hydrogen via pipeline. As of 2021, Howden Co. has released the most powerful reciprocating compressor yet, with a rated power of compression of 16.6 MW (Howden, 2021).

The main advantages of using a piston reciprocating compressor for the present case study are that it is a mature technology, since reciprocating compressors have a history of been used for compressing gases, as well as its ability to handle a wide range of different flow rates. On the other hand, disadvantages of using reciprocating compressors include powerful vibrations and noise, due to their several moving parts, as well as potential maintenance complications, for the same reason (Sdanghi et al., 2019).

2. Centrifugal Compressors:

Another compressor type that would be suitable for the application studied in this research would be the centrifugal type. As can be seen in the diagram of Figure 3.4, centrifugal compressors are dynamic devices and are mostly used when there is a high gas flow rate and moderate compression ratios. The way a centrifugal compressor achieves pressure increase is by providing velocity (kinetic energy) to a continuous fluid flow (The Piping Talk, 2020). As can be seen in Figure 3.6, centrifugal compressors compress the contained gas by using a rotating impeller with attached radial blades, used to increase the velocity of the gas (M. A. Khan et al., 2021). The kinetic energy is transformed into an increase in pressure via a diffuser.

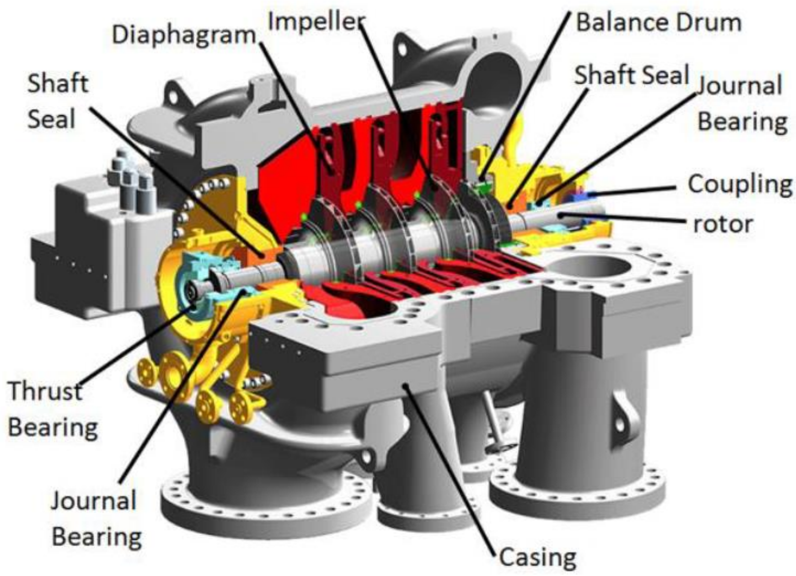

Figure 3.6 Components of a centrifugal compressor (The Piping Talk, 2020)

In contrast to reciprocating compressors, centrifugal compressor's compression ratio is heavily influenced by the contained gas's molecular weight. Compared to natural gas compression, hydrogen having a very low molecular weight (MW= 2.02 g/mole, making it the lightest gas) needs approximately three-times faster impeller tip speeds in order to be compressed (Barton et al., 2020). In case increased outlet pressures are required, the impeller speed needs to be raised, or extra stages of compressions need to be included (M. A. Khan et al., 2021). Similar to reciprocating compressors, centrifugal compressors' rotor is connected to a driving force (either electric motor or a thermal machine). Centrifugal hydrogen compressor design and development is a complex technical challenge, since it depends on a number of interrelated thermodynamic and mechanical metrics (Di Bella, 2015).

3. Other Types of Compressors:

Apart from reciprocating piston and centrifugal compressors, which are the most commonly used for large-scale hydrogen compression applications, there are also several other compression types that could be considered. Some other examples of mechanical compressors include reciprocating diaphragm compressors (a.k.a. membrane compressors), used mostly in hydrogen fueling stations

(HFS), ionic liquid compressors, capable of achieving high compression ratios and high efficiencies (mostly used in HFS), and other. Non-mechanical compressor examples include metal hydride compressors and electrochemical compressors, offering great potential advantages for H_2 compression, but still being in development stage (M. A. Khan et al., 2021; Sdanghi et al., 2019).

3.2.2 Compressor Selection: Reciprocating

The selection of the most suitable compressor type for the current application will be made by taking into consideration advantages and disadvantages of the aforementioned compression technologies. The decision will be made between reciprocating piston and centrifugal compressors, since, as explained in the previous section, these are two of the most prominent technologies for compressing H_2 for long-distance transportation.

Both centrifugal and reciprocating compressors have advantages when it comes to hydrogen compression. Specifically, centrifugal compressors are very well suited for increased throughputs (high flow rates) and moderate compression ratios (The Piping Talk, 2020), which accurately represents the compression requirements for the present case study. Furthermore, they are generally reliable machines, making it simpler to maintain and operate. On the other hand, reciprocating compressors also have some strong advantages, for example being a mature, widespread technology used for years in numerous applications, as well as being able to adjust to a wide variety of flow rates (Sdanghi et al., 2019).

Disadvantages of reciprocating compressors include strong vibrations and noise (due to the piston movement) and therefore require a stable substructure (i.e., platform) to support them. Another drawback of reciprocating compressors is the large number of moving parts included, thus making maintenance harder and increasing the chances of a mechanical failure or breakdown. Last but not least, reciprocating compressors could be prone to embrittlement phenomena, and, thus, the materials for its development need to be carefully selected (Sdanghi et al., 2019). Regarding centrifugal compressors, disadvantages may include a lower technological maturity compared to reciprocating, and a poor operation adaptability (Bailan Compressors, 2019). Nevertheless, the most important boundaries of hydrogen compression with centrifugal compressors, which make them unfit for the studied application, are the surge and choke phenomena, as will be analysed below.

Surging & Choking Phenomena: Centrifugal Compressors

Surge of centrifugal compressors is one of the most crucial boundaries in compressing hydrogen (same applies also for natural gas). The surge point is the point at which the compressor is no longer in position to provide sufficient energy to the contained gas in order to force it out of the compressor, causing an instantaneous inversion of the gas flow (Frend, 2016). In other words, surging is the phenomenon caused by a reduced gas flow rate through the compressor (less than a predetermined value – operating flow). Depending on the gas characteristics, as well as the number of impellers in the centrifugal compressor's case, surging typically occurs at 50 – 80% of the design flow (Frend, 2016).

In case surging takes place in a centrifugal compressor, it could affect the entire machine and seriously damage the operability of the blades by placing them under excessive vibrational stress (Kim, 2019). The surge area can be seen in the diagram of Figure 3.7, between points A and B, representing the flow rates for which the gas flow surges back through the compressor.

Apart from surging, centrifugal compressors pose limitations when it comes to maximum flow as well. Specifically, a phenomenon called choking (also known as stonewalling) takes place when the gas flow rate exceeds a certain level, creating complications to the machine. The choke point (Point E on Figure 3.7) represents the actual maximum gas flow rate that the compressor can endure (EnggCyclopedia, 2020). Protracted operation of a centrifugal compressor at its choke point limit could severely damage various components of the machine and, thus, should be avoided. Therefore, the useful operating range (stable flow) for a centrifugal compressor is between point B (Surge point) and point E (Choke point).

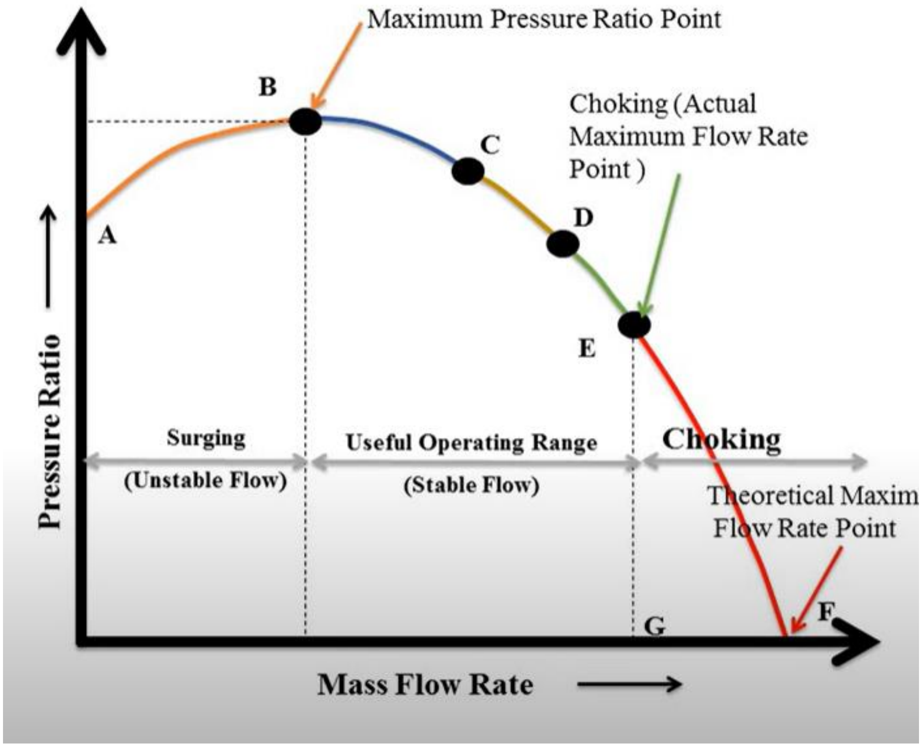

Figure 3.7: Surging and Choking of a centrifugal compressor depending on the mass flow rate and pressure ratio: AB: Surge area - unstable flow; BE: Useful Operating Range – stable flow; EF: Choke area

In the present case study, according to the system configuration, the hydrogen flow is assumed not to be stable, but fluctuating, given that the energy for its production comes from wind turbines. This implies that there could be instances that powerful winds cause increased hydrogen flow, while on the other hand, lower wind speed conditions could result in significantly decreased hydrogen flow. Therefore, in order to avoid choking and surging phenomena that occur when using centrifugal compressors, we opt for **reciprocating compressors**.

3.2.3 Compression Stations

As will be analysed in the compression modelling chapter of this report, it is found that the number of compressors required to handle the hydrogen produced by the total of 10 GW offshore wind are 7. Those are assumed to be allocated: 5 compressors in S.A.7 and 2 compressors in S.A.3, given that the maximum rated power of each compressor is assumed to be approximately 16 MW (Khan et al., 2021).

These compressors are assumed to be placed in compression stations, located on offshore platforms near the wind farms, which will be also hosting other necessary components. More specifically, apart from the compressor itself, a compression station should mainly include a compressor driver (also known as primary mover) to supply the compressor with energy, as well as a gas treatment unit, to ensure the purity of the incoming hydrogen (IFS, 2019). An offshore gas compression station is depicted in Figure 3.8, to showcase what a large-scale offshore hydrogen compression station would look like.

Figure 3.8: Offshore gas compression station (platform). (Credit: McDermott)

A key component of a compression station is the driver of the compressor, which will provide the required power for the compression to be achieved. Typically, for gas compression using a reciprocating device, there are two main types: electrically driven and engine driven compression. Natural gas transportation is typically powered by gas motors, using part of the natural gas as a fuel for the engine. However, this is not a preferable solution for hydrogen, due to its low volumetric energy density, which implies that large volumes of hydrogen would be required to power up the motor. Furthermore, gas turbines operate with relatively low efficiencies, meaning that a lot of energy would be lost. Therefore, the most suitable option for hydrogen compression would be an electric motor to power the reciprocating compressor, utilizing generated electricity. An additional advantage of electric motor prime movers is that they are typically easier to maintain compared to gas turbines (IFS, 2019). A suggested solution for providing the electric motor with electricity would be to couple it with an offshore wind turbine located in close proximity.

The North Sea has numerous offshore platforms capable of hosting hydrogen compression stations. However, these are not always placed at the most suitable locations for the requirements of this study (close to search areas 7 and 3 and the NGT pipeline), so there might be a need for relocating them, which would include extra costs. Another option would be to design and develop new platforms, in order to place them exactly where needed. In case the compressor's electric motor is powered by offshore wind, the compressor could be placed either in the wind turbine itself or on top of the wind turbine foundation (or on the floater component – in the case of using floating wind turbines), to also avoid the additional cost of building new offshore platforms. Nevertheless, this part, not being in the direct scope of this study, needs further investigation.

Figure 3.9: Offshore floating wind turbine including its foundation, on top of which the compressor station could be potentially placed

3.3 Infield Pipelines & Wind Farms Layout

As analysed in Chapter 2, the offshore wind search areas that are proposed to be used in this case study for wind farm development are search area 7 and search area 3. The total space provided by those could accommodate around 10 GW of offshore wind (search area 7: 8 GW and search area 3: 2 GW), according to Rijksoverheid (2022). With back of the envelope calculations, taking into account that the nominal power of each wind turbine is 15 MW, we can conclude that there is a requirement of around 670 wind turbines in total, to achieve the 10 GW potential. Since the offshore wind farm arrangement part is not in the direct scope of this study, the analysis made is not in depth, but rather on a basic level (not taking into account wake effect or other technical considerations for the accurate design of the wind farms).

After green hydrogen is produced by in-turbine electrolyzers in each individual wind turbine, it needs to be compressed in order to be transported to the shore. As analysed in Section 3.2, compression is proposed to take place in compression stations located near the NGT pipeline, to be directly fed into it, without major infrastructure additions. The linkage between each turbine and the compression station is assumed to be achieved via infield pipelines with relatively small diameter, which are placed within the wind farm space as the name suggests. The way infield pipelines work is similar to inter-array electricity cables, used more frequently in offshore wind farms, connecting an array of wind turbines to a substation, which houses electrical components for power transformation. As can be seen in Figure 3.10, each infield pipeline starts from the wind turbine located further away from the compression point, connecting each turbine to its neighbour, and creating a string, so that all hydrogen produced by this particular array of turbines can be fed into it and travel to the compressor station.

Figure 3.10: Hydrogen transportation via infield pipeline: Offshore wind turbine array overview. (Credit: 4FR / Getty Images)

After analysing several different potential configurations, the resulting layouts of the wind farms, infield pipelines, and compression stations for search areas 7 and 3 are depicted in the sketches of Figures 3.11 and 3.12 respectively. The analysis was made on the basis of how many wind turbines could be connected to a single infield pipeline without requiring additional compression, since that would imply significant cost addition. Hydrogen is assumed to be coming out the in-turbine electrolyzer with a pressure of 30 bar (Brun & Allison, 2022; Roobeek, 2020; Zervas, 2021). The total length of each infield pipeline needs to be short enough for the produced hydrogen to be transported to the compression stations without significant pressure losses. More detailed information on the infield pipelines modelling will be presented in the Appendix.

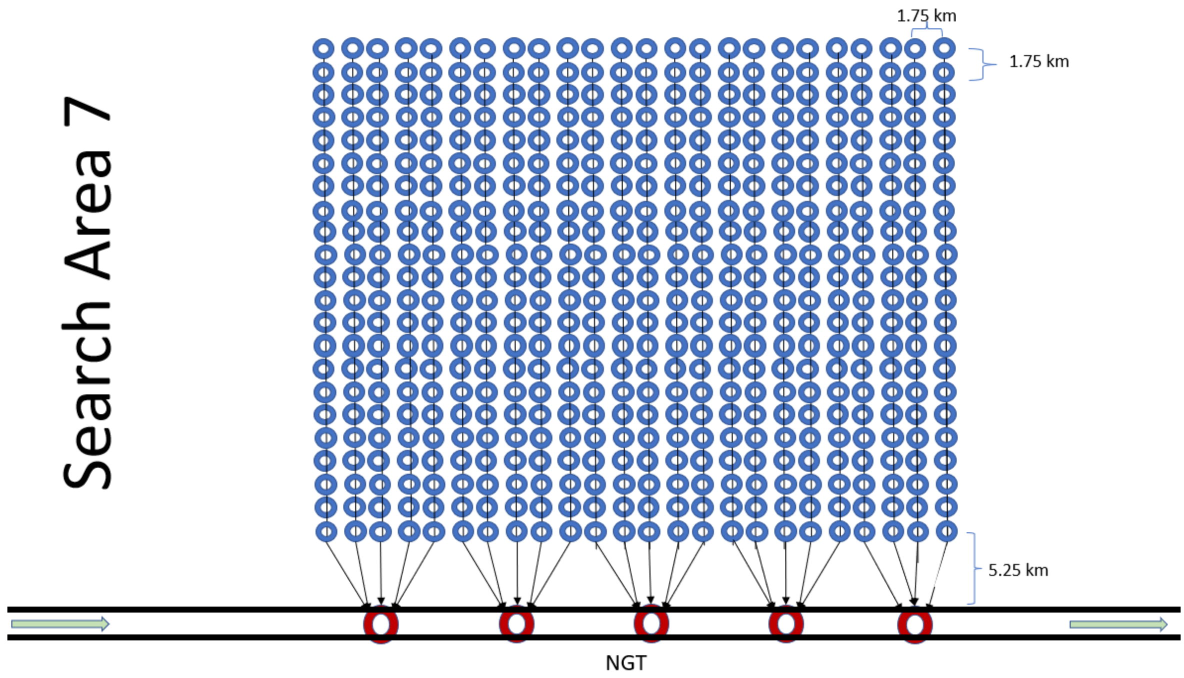

Figure 3.11: Proposed layout for offshore wind search area 7, including infield pipelines and compression stations (red circles)

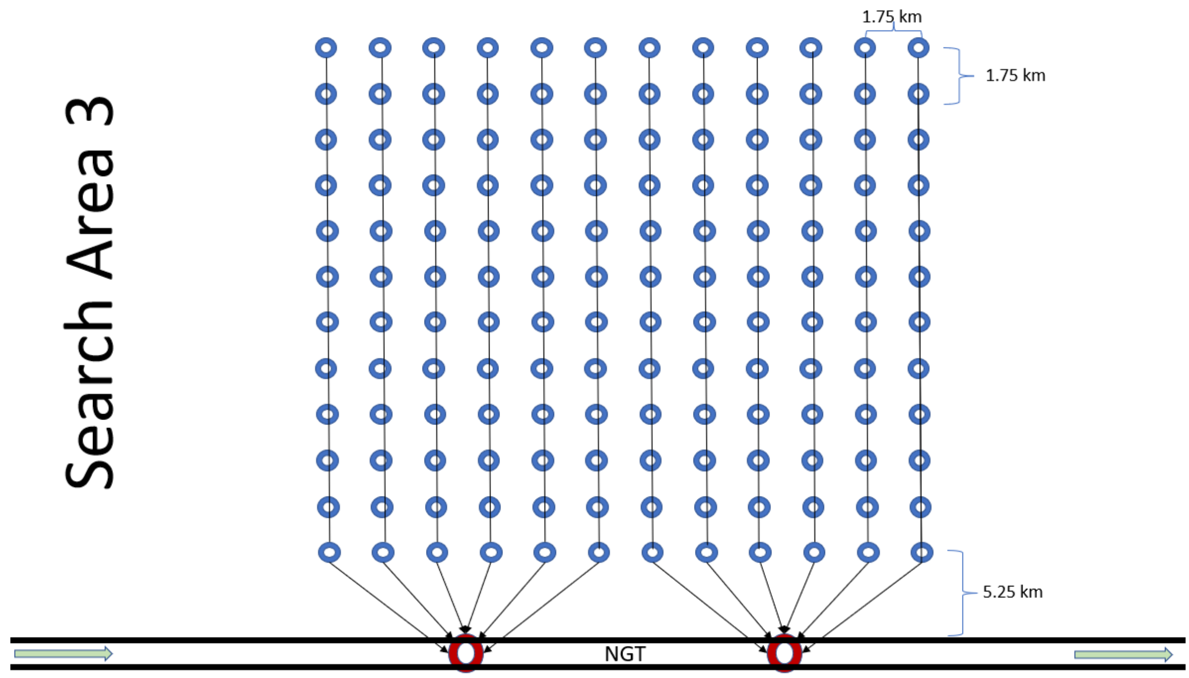

Figure 3.12: Proposed layout for offshore wind search area 3, including infield pipelines and compression stations (red circles)

3.4 Hydrogen Transportation via NGT Pipeline

The final key component of the system configuration is the NGT pipeline, which is proposed to be repurposed to facilitate the transportation of the produced green hydrogen to the Dutch shore. As explained in Section 2.4 of this report, currently the NGT pipeline is used as a transmission pipeline to transport natural gas from several gas fields in the North Sea to the gas processing station in Uithuizen, in the northern part of the Netherlands (Neptune Energy, 2022b).

3.4.1 Repurposing Natural Gas Pipelines for Hydrogen Transportation

Repurposing already existing natural gas infrastructure to be utilized for transporting hydrogen is highlighted as a cost-effective method to replace natural gas with hydrogen in a future energy system. Specifically, the capital costs of repurposing existing gas pipes, are estimated to be a fraction (10-35%) of the capital cost of developing new dedicated hydrogen infrastructure, as follows from projects and research carried out by several European gas TSOs (European Hydrogen Backbone, 2020).

The repurposing procedure mainly comes down to eliminating unwanted components and creating a safer environment by performing nitrogen purging (Generon, 2018), thoroughly inspecting the pipeline for potential fractures, and substituting existing valves which have been in use for a long period of time. In addition, natural gas pipelines repurposed for hydrogen transport generally need to operate at reduced pressure, albeit this might be prevented by installing an interior coating layer (European Hydrogen Backbone, 2020). However, for the pressure levels examined in the case of this thesis, this does not constitute a problem. In general, the two key features that make repurposing natural gas pipelines into hydrogen an attractive solution are the low converting cost, as well as the relatively simple technological conversion process. According to the European Hydrogen Backbone study, more than 60% of the dedicated hydrogen network in Europe by 2040 is expected to be comprised of retrofitted natural gas pipelines (European Hydrogen Backbone, 2022).

Regarding the NGT pipeline, according to input provided by NGT in an interview, there are not many actions necessary for the repurposing to be completed (R. Hagen, M. Ros, personal communication, October 11, 2022). Generally, changing all side taps and valves along the pipeline would be required, however the NGT's certification exercise (completed by Bureau Veritas in October 2022) stated that this is not necessary for this case. However, extensive monitoring of the pipeline is required, in order to identify and locate any hydrogen leaks. In case no leaks are found, no action is necessary. If leaks are located, which is possible since the H_2 molecule is much smaller than a methane (CH_4) molecule, action needs to be taken to intervene and replace the defective part of the pipeline. Apart from the aforementioned actions, cleaning the pipeline from the natural gas also needs to take place, in order for hydrogen to be transported. Therefore, according to the NGT operators, the CAPEX of repurposing the NGT pipeline could amount to less than 10% of the CAPEX of developing a new pipeline, since hardly any high-cost activities are involved.

3.4.2 Hydrogen vs Natural Gas Transportation via Pipelines

Although converting a natural gas pipeline to hydrogen might not be very challenging from a technical standpoint, there are still several aspects that differentiate hydrogen from natural gas transportation in pipelines, which need to be addressed. These are mainly derived from the different characteristics and distinctive qualities of the two gases. In Table 3.2 the properties of hydrogen and methane (the main component of natural gas, with a molar fraction of 93.76%) are presented.

Table 3.2: Main Characteristics of Methane (Natural Gas) and Hydrogen at 100 bar and 303 K (Abbas et al., 2021)

Property	Methane	Hydrogen
Molecular weight (g/mol)	16.0425	2.0159
Density (kg/m^3)	74.6208	8×10^{-3}
Specific gravity	5.539×10^{-1}	6.96×10^{-2}
Dynamic viscosity (Pa·s)	1.3955×10^{-5}	9.168×10^{-6}
Kinematic viscosity (m^2/s)	1.8702×10^{-7}	1.15×10^{-3}
Gross heating value (MJ/m^3)	37.6315	12.0793
Thermal conductivity (W/(m·K))	4.48×10^{-2}	1.561×10^{-1}

- **Challenges**

Due to those differences between the properties of the two gases, various challenges might arise when transporting hydrogen via natural gas pipelines. The main difference of the two is their energy content: as can be also seen in Table 3.2, natural gas has approximately three-times higher heating value than hydrogen. Apart from that, hydrogen, being the smallest molecule, is more prone to leakage from natural gas pipelines and moreover, steel gas pipelines could be more sensitive to embrittlement when carrying hydrogen (Witkowski et al., 2017).

On the other hand, one of hydrogen's advantages is its increased compressibility properties. Compared to natural gas, hydrogen's compressibility could make it possible for it to be transported at reduced pressure levels, therefore lowering the chance of embrittlement in steel pipelines (Kurz et al., 2020). Consequently, apart from investigating the amount of hydrogen that could offer equal energy content with natural gas, there is also a need to analyse the impact of flow characteristics (e.g., velocity, compressibility factor) for the secure and reliable transportation of hydrogen through the pipeline (André et al., 2014). Regarding hydrogen's volumetric flow rate inside the pipeline, it needs to be approximately triple the natural gas's, considering the three times lower energy content compared to natural gas, in order to transport the same amount of energy at the same time (Abbas et al., 2021). However, it is critical to emphasize that increased hydrogen volumetric flow rates would lead to increased compression energy requirements as well. Given that the flow rate directly impacts the power of compression, approximately three times more compression energy would be required to compress same amount of hydrogen compared to natural gas, with regard to their energy content (M. Khan et al., 2021).

Regarding the hydrogen embrittlement issue, studies conducted by DNV-GL and Bureau Veritas have shown that it does not prevent the repurposing of the NGT pipeline for hydrogen transport, as it will operate within safe boundaries. In fact, as mentioned in Section 2.4, in October 2022 the NGT pipeline was officially certified as suitable for green hydrogen transportation for 40 years by Bureau Veritas, after an elaborate assessment (Bureau Veritas, 2022). Specifically, according to information provided by NGT during an interview, the certification exercise included an assessment of the actual design of the NGT and NOGAT pipeline system, including the material specifications, and showcased that there are no major showstoppers for transporting hydrogen (R. Hagen, M. Ros, personal communication, October 11, 2022). However, to verify the pipeline's structural integrity, the NGT operators need to monitor the system's side taps and perform an inline inspection (additional to the regular inline inspection taking place every 5 years), checking for microcracks on the pipeline walls, in order to ensure that hydrogen will not enter the metal framework and cause embrittlement.

- **Pressure Drop**

An important characteristic of gases flowing through a pipeline is pressure drop. Regarding the gas flow through a cylindrical pipeline with no elevation difference between the starting and ending points, the pressure at the start should be greater than it is at the end, to act as a driving force (Menon, 2005). The pressure experiences a decrease along the pipeline, also referred to as pressure drop, because of the friction between the gas and the pipeline (M. Khan et al., 2021). In fact, the pressure loss of a gas flowing in a pipeline is dependent on the length of the pipe, the gas flowrate, as well as the characteristics of the gas and the pipeline wall (Ahmed, 2010). In Figure 3.13 one can see the gas pressure dependence on the length of the pipeline (longer pipeline: higher pressure drop) as well as on the gas flow rate (higher flow rate (d): higher pressure drop). According to González Díez et al., (2020), a pressure drop level of 3 – 10 bar per 100 km would be expected in a common North Sea pipeline.

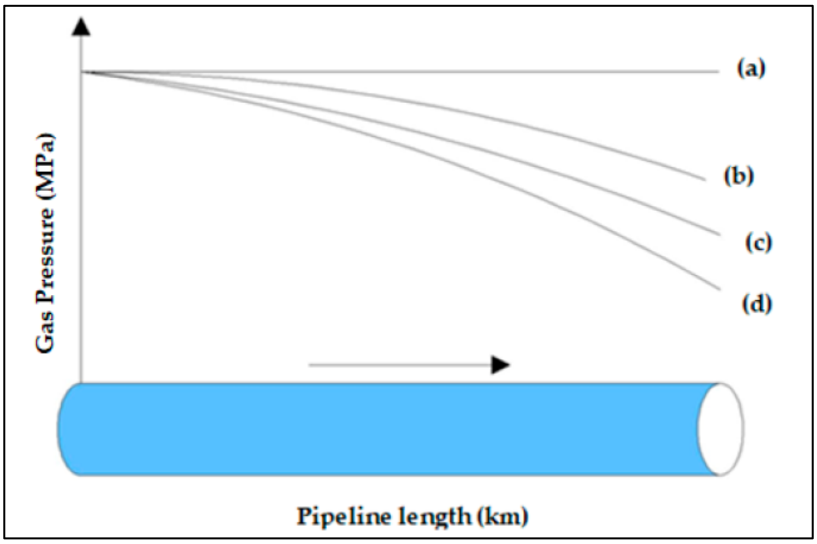

Figure 3.13: Gas Pressure as a function of pipeline length. Gas flow rates: (d)>(c)>(b), (a): No flow (Abbas et al., 2021)

The drop of pressure for a gas flowing through a pipeline also causes a rise in the velocity of the gas. Specifically, this velocity increase is due to the continuous expansion of the gas, as the collision of the gas molecules with the inner walls of the pipe leads to pressure losses, because of friction (Abbas et al., 2021). The vast density difference between hydrogen and natural gas suggests that hydrogen's velocity in gas pipelines is generally higher than natural gas's velocity (Abbas et al., 2021). Figure 3.14

illustrates the change in the velocity of the gas flowing through a pipeline, showcasing a reverse behaviour compared to pressure drop.

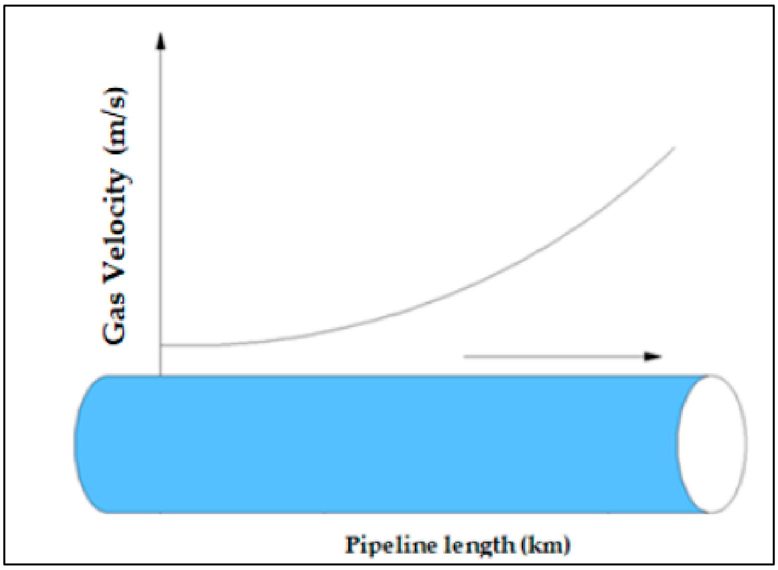

Figure 3.14: Gas velocity profile along the length of a pipeline (Abbas et al., 2021)

3.4.3 Hydrogen Specifications When Reaching the Shore

Regarding the quality requirements of the transport network, as more hydrogen is produced using electrolysis and more knowledge is gained about transporting, storing, and cleaning hydrogen, it is expected that in time the quality requirements can be adjusted to purities higher than 98% (DNV & Kiwa, 2022). DNV & Kiwa, (2022) recommend that the specifications are re-established three years after the hydrogen transport network is commissioned, taking into account the developments in green hydrogen production, the actual contaminations coming from the transport network and how these develop over time, and the hydrogen market development. It should be noted that the proposed specifications involve hydrogen produced by any of the current production methods (including SMR), hence organic compounds are also included (e.g., CO, CO_2, hydrocarbons). For green hydrogen (produced by electrolysis) such compounds would normally not be present in the hydrogen stream.

Table 3.3: Basic preliminary specifications for hydrogen in the transport network for both entry and exit points (DNV & Kiwa, 2022)

Parameter	Value	Unit
Hydrogen	≥ 98	mol %
Hydrocarbons	≤ 1.5	mol %
Oxygen	≤ 10	ppm
Carbon Dioxide	≤ 20	ppm

Total Sulfur content (incl. H_2S)	≤ 3	ppm
Halogens	≤ 50	ppb
Carbon Monoxide	≤ 20	ppm
Formic Acid	≤ 10	ppm
Ammonia	≤ 10	ppm
Formaldehyde	≤ 10	ppm

The specifications presented in Table 6.1, are recommendations made by DNV & Kiwa, (2022) for the hydrogen transport network for the period up to 2025. Although the specifications might be slightly adjusted until around 2030 (proposed timeline for this project), this is the most up-to-date specification list for the Dutch hydrogen transport network at the time of writing this report.

4

System Modelling

Having analysed the physical configuration of the system as well as the associated components, this chapter will discuss the modelling of the suggested system on two levels: Technical and Economic, and describe the methodology used. Each part of the system will be analysed, from the energy production from offshore wind to the transportation of the produced green hydrogen through the NGT pipeline, placing more emphasis on the hydrogen compression and transportation aspects.

4.1 Technical Analysis

4.1.1 Offshore Wind

As analysed in the previous chapter, the offshore hydrogen production is proposed to take place with offshore in-turbine electrolysis. Offshore wind turbines are proposed to be placed in designated wind search areas 7 and 3 in the North Sea, with a combined power potential of 10 GW (8 GW in search area 7 and 2 GW in search area 3). For simplicity, the two offshore search areas will be considered as a single one, with a maximum capacity of 10 GW. As presented in Section 3.1.2, the nominal capacity of the suggested wind turbines will be 15 MW. Regarding the offshore wind turbines operation, this is assumed to be 5,000 full-load hours per year. This assumption is based on literature and is considered a good approximation for the North Sea: Guidehouse & Berenschot, (2021) approximate 4,500-5,000 full load hours, referring to coupled offshore wind-electrolysis for the North Sea, which is verified by Badger et al., (2020), stating that offshore wind, as has been modelled for the European Commission, could reach 5,000 full-load hours at sites with strong wind potential. 5,000 full-load hours per year translates to a capacity factor of 0.57 for the offshore wind turbines. It is worth to be noted that capacity factors for offshore wind could reach 6,000 full-load hours (van Wijk, 2021b).

Dividing the full potential capacity of both wind search areas (10 GW) with the nominal power of a single offshore wind turbine (15 MW), we conclude that the total number of wind turbines required to produce such output is around 667 (simplified: not taking the wake effect into consideration). More information and elaborate analysis on the layout (for search area 7 and 3 individually) and number of wind turbines can be found in Section 4.1.5.

It is assumed that not the entirety of the wind energy will be dedicated to hydrogen production, but rather 99.5% of it. This assumption is made, in order to also account for the energy requirements of other components of the system (0.5%), mainly for the hydrogen compression unit (but also for gas treatment, seawater desalination etc). The energy input into the electrolysis unit for hydrogen production in TWh on a yearly basis is calculated as follows:

$$\text{Energy}_{\text{ for } \mathrm{H_2} \text{ production}}\ (\text{TWh/y}) = 99.5\% \cdot \frac{\text{Total wind capacity} \cdot \text{Full load hours}}{1000} \tag{4.1}$$

Where the total wind capacity is the total installed wind turbine capacity (GW) in search areas 7 and 3, the full-load hours are the number of hours in a year that the wind farms will be operational (h/y), and the division by 1000 takes place to express the result in TWh/y instead of GWh/y.

All the assumptions and considerations for the offshore wind turbines modelling are summarized in Table 4.1.

Table 4.1: Data and assumptions for the offshore wind analysis

Search Area 7 capacity	8	GW
Search Area 3 capacity	2	GW
Combined capacity	10	GW
Full-load hours	5,000	h/y
Capacity Factor	0.57	-
Number of Wind Turbines	667	-
Percentage of energy for hydrogen production	99.5	%
Energy Input for the electrolyzer	49.75	TWh/y

4.1.2 Offshore Green Hydrogen Production: Electrolysis

Although the electrolysis for hydrogen production will take place in-turbine, as proposed in the previous chapter, the modelling of the two parts (offshore wind and electrolysis) is done individually. In this section, the amount of green hydrogen produced by water electrolysis will be calculated, explaining the methodology and assumptions made. As mentioned in the previous chapter, alkaline electrolyzer technology is preferred for the studied application, since it is a mature technology with higher efficiency, lower capital cost, and greater lifetime than PEM (Buttler & Splietho, 2017; IRENA, 2020; Roobeek, 2020). The amount of energy required for producing one kilogram of hydrogen (also referred to as specific electricity consumption) is approximately 50 kWh/kg, although it is expected to further reduce in the coming years, due to advance of technology (Carbon Commentary, 2021; van Wijk, 2021a). Therefore, in this case study the 50 kWh/kg $_{\text{Hydrogen}}$ value is assumed as the electricity requirement for hydrogen production. Accordingly, the electrolyser's efficiency is found to be 78.8%, using the higher heating value (HHV) of hydrogen, as can be seen in equation 4.2. Table 4.2 presents the main electrolyzer parameters and hydrogen properties used for modelling the electrolysis process.

$$\text{Electrolyzer Efficiency (\%)} = \frac{\text{HHV}_{\text{H}_2}}{\text{Electricity requirement for producing 1 kg H}_2} \tag{4.2}$$

Where HHV_{H_2} is the higher heating value for hydrogen (39.4 kWh/kg), and the electricity requirement for the production of 1 kg H_2 is taken as 50 kWh/kg, as explained in the previous paragraph.

Referring to a fuel gas's energy content as a reference volume makes more sense scientifically. Furthermore, it is more appropriate to conduct this analysis using the gross calorific value (HHV - heat of formation) instead of the LHV, since it represent the actual energy content of the fuel, in accordance with the concept of the 1^{st} Law of Thermodynamics (energy conservation). Since hydrogen production is determined by the heat of formation (HHV), its utilization has to also be correlated with its energy content expressed in HHV terms. Therefore, throughout this research the higher heating value of hydrogen is applied ($HHV_{Hydrogen}$ = 39.4 kWh/kg = 141.9 MJ/kg, at 25 ^{o}C and 1 atm).

Table 4.2: Technical characteristics of electrolyzer (Brun & Allison, 2022; Calado & Castro, 2021; Guidehouse & Berenschot, 2021; Roobeek, 2020)

Electricity Requirement	50	kWh/kg $_{Hydrogen}$
Efficiency on $HHV_{Hydrogen}$	78.8	%
Outlet Pressure	30	bar
Full-load hours	5,000	h/y
Specific Energy Content on $HHV_{Hydrogen}$	39.4	kWh/kg

The electrolyzer is assumed to be operating for 5,000 full-load hours per year, same as the offshore wind, since there are no intermediary conversion or transportation losses (Guidehouse & Berenschot, 2021). Regarding the capacity of the electrolyzer, this is assumed to be 10 GW, again similar to the offshore wind, as there is a need to account for the maximum wind energy output scenario. The electrolyzer needs to be able to compensate for the entirety of the wind capacity. The amount of the produced hydrogen (kg/h) for this analysis is calculated as can be seen below:

$$\text{Hydrogen Production (kg/h)} = \frac{\text{Energy}_{\text{for H}_2\text{ production}}}{\text{Electricity requirement for producing 1 kg H}_2} \tag{4.3}$$

Where the Energy for H_2 production (TWh/y) refers to the energy produced by the wind turbines, utilized for production of green hydrogen, as calculated by equation 4.1, and the electricity requirement for producing 1 kg H_2 is taken as 50 kWh/kg, as explained previously.

4.1.3 Hydrogen Transportation: NGT Pipeline Hydraulics

After having calculated the total amount of hydrogen produced by the electrolyzers, the next step in the process would be hydrogen compression. As described in the previous chapter, compression is required as a driving force for the produced hydrogen to travel to the shore. Given that a pressure greater than 50 bar is expected in the onshore hydrogen pipeline network (according to information provided by Gasunie, as analysed in Section 3.2), and the outlet pressure of the electrolyzers is taken as 30 bar, extra compression near the production site needs to take place, in order for hydrogen to reach the shore at the required final pressure level and compensate for the pressure loss along the pipeline as well.

Table 4.3: Main assumptions for hydrogen's pressure (Breunis, 2021; Brun & Allison, 2022; Roobeek, 2020; Zervas, 2021)

Onshore expected hydrogen pressure	> 50	bar
Electrolyzer outlet pressure	30	bar

Pressure Drop

In order to determine the level of compression (compressor outlet pressure), we first need to analyse the hydrogen flow hydraulics and calculate the pressure drop (ΔP) in the pipeline. As explained in the previous chapter, pressure drop (bar) is a result of the friction between the flowing gas and the pipeline walls. In this analysis, the Darcy Weisbach equation was used for this calculation (Twidell & Weir, 2015):

$$\Delta \mathrm{P}\ (\mathrm{bar}) = \frac{1}{2}\frac{\mathrm{L}}{\mathrm{D}}\rho \mathrm{v}^2 \mathrm{f} \tag{4.4}$$

Where L is the length of the pipeline (m), D is the internal diameter of the pipeline (m), ρ is the gas's density ($kg \cdot m^{-3}$), v the gas's mean flow velocity (m/s), and f is the Darcy friction factor coefficient (dimensionless). More in-depth analysis on how these values are calculated will be presented below. The calculation was performed for the total length of the NGT pipeline (253.2 km), broken down into 10 m intervals, resulting in a detailed analysis of the pressure drop phenomenon.

Figure 4.1 depicts a simplified sketch of a pipeline section, including its length, inlet and outlet pressures, and diameter. Given that the North Sea has a relatively flat (and shallow) seabed, we assume no elevation difference (ΔH) between the start and end points of the pipeline (H_1=H_2) (MSP, 2022).

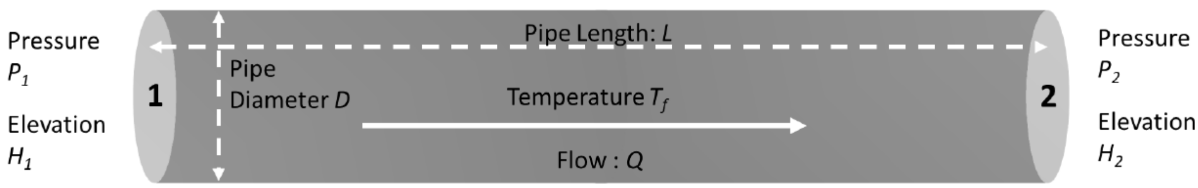

Figure 4.1: Schematic representation of steady gas flow (Q) in a pipeline (M. Khan et al., 2021)

Hydrogen Density

As described in Section 3.4.2, while the gas flows inside the pipeline, it experiences a pressure drop, but also its velocity increases. Apart from that, the gas's actual density is not constant along the pipeline, but changes as well, since it is dependent on the gas's pressure (and temperature) at any given point, as derived from equation 4.5:

$$\rho_{actual}\ (kg \cdot m^{-3}) = \frac{P_{H_2}}{P_b} \cdot \rho_{H_{2NTP}} \cdot \frac{T_b}{T_{H_2}} \tag{4.5}$$

Where P_{H_2} (bar) is the hydrogen's pressure at a given point inside the pipeline, P_b (bar) and T_b (K) are hydrogen's base pressure and temperature respectively (also known as standard conditions), T_{H_2} (K) is the temperature of the hydrogen gas at the same point, and $\rho_{H_{2NTP}}$ ($kg \cdot m^{-3}$) is hydrogen's density at NTP conditions. Hydrogen's properties that are used for these gas flow calculations can be found in Table 4.4.

Since density is defined as the quantity of mass per unit volume, density data are meaningful when expressed for a certain pressure and temperature, as each of these variables has an impact on the denseness level of the examined material. Therefore, regarding hydrogen, which is classified as a compressible gas, its density should be corrected (actual density: ρ_{actual}) to account for the level of pressure that it is compressed at (Pahwa & Pahwa, 2014). In this analysis, the aforementioned density correction is employed for each hydrogen pressure measurement throughout the course of the pipeline.

Table 4.4: Hydrogen gas parameters used in the flow calculations (André et al., 2014; Engineering Toolbox, 2008; Guidehouse & Berenschot, 2021; NIST, 2021; van Schot & Jepma, 2020)

Parameter	Symbol	Value	Unit
Base Pressure	P_b	1.01325	bar
Base Temperature	T_b	273.15	K
Density (NTP)	$\rho_{H_{2NTP}}$	0.08375	$kg \cdot m^{-3}$
Compressibility Factor	Z	1.03	-
Viscosity (at 20°C)	μ	$0.885 \cdot 10^{-5}$	$kg \cdot m^{-1}\ s^{-1}$
Specific Gravity	G	0.0696	-
Molecular Weigh	M	2.0158	$g \cdot mol^{-1}$
Ideal Gas Constant	R	8.314	$J \cdot K^{-1}\ mol^{-1}$
Diatomic Constant Factor	γ	1.4	-

Hydrogen Temperature

Regarding the temperature of the hydrogen gas inside the pipeline (T_{H_2}), it is assumed to be constant and equal to 10 °C (= 283.15 K), which is an approximation of the average temperature of the North Sea on a yearly basis (MacKenzie & Schiedek, 2007; van Schot & Jepma, 2020). As a result, the reference point and the ambient temperature are assumed to be in thermal equilibrium (González Díez et al., 2020). Throughout a gas pipeline, usually a phenomenon known as the 'Joule – Thomson' effect takes place, according to which the temperature of the gas changes as a result of changes in pressure (European Hydrogen Backbone, 2020). Specifically, when the majority of gases undergo expansion from higher to lower pressure (pressure drop), their temperature decreases (Barton et al., 2020). However, gaseous hydrogen has a different behaviour when experiencing a pressure drop, known as the 'Reverse Joule – Thomson' effect (also referred to as 'inverse Joule – Thomson' effect). Contrary to most gases' reaction when exposed to pressure drop, hydrogen warms up when expanded at temperatures higher than -80 °C (inversion point) (Barton et al., 2020).

In the case of natural gas, when it experiences a pressure drop when flowing inside a pipeline, its temperature drops by approximately 0.5 °C/bar. On the other hand, the 'Reverse Joule – Thomson' coefficient for hydrogen is around 0.035 °C/bar (temperature rise) (European Hydrogen Backbone, 2020). For example, for a pressure drop level of 10 bar, natural gas's temperature would drop by 5 °C, whereas hydrogen's temperature would rise by 0.35 °C (negligible increase, hence considered a constant).

Friction Factor:

A crucial parameter, necessary for calculating a gas's pressure drop when analysing its flow inside a pipeline, is the Darcy friction factor (also referred to as friction factor). The friction factor (f) depends on the internal roughness of the pipeline as well as on the flow type of the gas inside the pipe (laminar, turbulent, or crucial flow) (Menon, 2005). The type of flow inside the pipeline is determined by calculating the Reynolds number, as will be explained below. Typically, for the calculation of the friction factor the Moody diagram is used (Figure 4.2). For graphically estimating f via the Moody diagram, one needs to know the Reynolds number (Re), as well as the pipeline's relative roughness (e/D).

$$Re = \frac{\rho v D}{\mu} \tag{4.6}$$

Where ρ is the average density of the gas (kg·m^{-3}), D is the internal diameter of the pipeline (m), v is the average gas's velocity (m/s), and μ is the viscosity of the gas (kg·m^{-1}·s^{-1}) (Twidell & Weir, 2015). The Reynolds number is dimensionless and can be also calculated by formula 4.7 (used for verification in this analysis – typically used in the gas pipeline industry (Menon, 2005)):

$$Re = 0.5134 \left(\frac{P_b}{T_b}\right)\left(\frac{GQ}{\mu D}\right) \tag{4.7}$$

Where P_b (kPa) and T_b (K) are hydrogen's base pressure and temperature respectively, G (dimensionless) is the specific gravity of the gas, D is the internal diameter of the pipeline (mm), Q is the gas flowrate (m^3/d), and μ is the viscosity of the gas (Poise).

In case the value of the Reynolds number is over 4,000, the gas flow in the pipeline is considered to be turbulent. When the Re value is within the 2,000 and 4,000 range, the flow is considered as critical (or undefined), and for Reynolds numbers below 2,000 the gas flow is considered to be laminar (Menon, 2005). The Re values with the respective gas flow regime are summarized in Table 4.5.

For calculating the dimensionless pipeline's relative roughness (e/D), one needs to divide the absolute internal roughness of the pipeline (e) with its inside diameter (D).

Table 4.5: Reynolds number values and respective gas flow regimes

$Re > 4{,}000$	Turbulent Flow
$Re \leq 2{,}000$	Laminar Flow
$2{,}000 < Re \leq 4{,}000$	Critical Flow

In reality, the majority of gas pipelines run at relatively high gas flow rates, resulting in increased Reynolds number values. This usually translates to turbulent flow regimes (Menon, 2005)

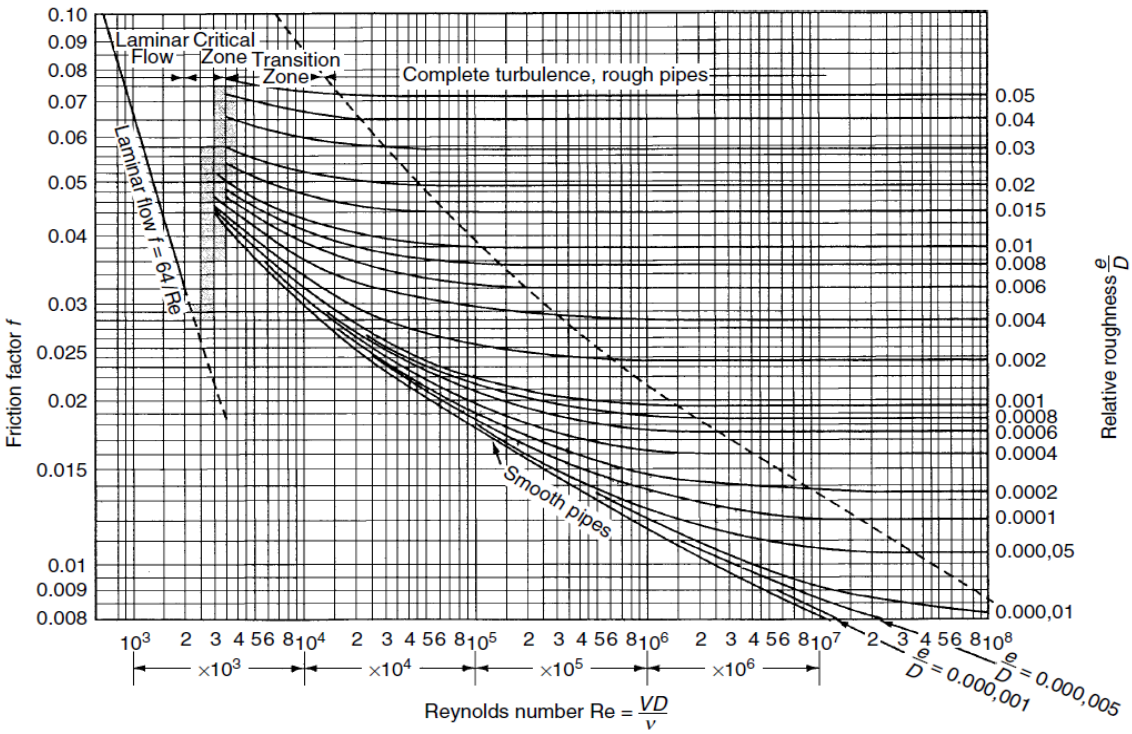

Figure 4.2: Moody Diagram for calculating friction factor

Another way of calculating the friction factor, without a graphic solution from the Moody diagram, when the gas flow in the pipeline is turbulent, is through formula 4.8 which is also known as the Colebrook-White equation (Hall, 2012):

$$\frac{1}{\sqrt{f}} = -2\log_{10}\left(\frac{e}{3.7D} + \frac{2.51}{Re\,\sqrt{f}}\right) \tag{4.8}$$

Where f is the friction factor (dimensionless), D is the inside diameter of the pipeline (inch), e is the absolute internal roughness of the pipeline (inch), and Re is the Reynolds number.

Pressure Drop Verification:

Apart from the Darcy – Weisbach equation (4.4), the gas pipeline industry has created a number of additional flow equations for the analysis of the gas flow through a pipeline, including the General Flow equation (also known as the Fundamental Flow equation), the Weymouth equation, and the IGT equation, as can be seen below (equations 4.9 – 4.11), expressed in SI units. These equations were used in this study to verify the calculated pressure drop for hydrogen flowing through the NGT pipeline. All symbols used have already been defined in the previous section of this report.

General Flow equation:

$$Q\ (m^3/d) = 1.494x10^{-3}\left(\frac{T_b}{P_b}\right)\left(\frac{p_1^2 - p_2^2}{GT_fLZf}\right)^{0.5} D^{2.5} \tag{4.9}$$

Weymouth equation:

$$Q\ (m^3/d) = 3.7435 \times 10^{-3}E\left(\frac{T_b}{P_b}\right)\left(\frac{p_1^2 - e^s p_2^2}{GT_fLZ}\right)^{0.5} D^{2.667} \tag{4.10}$$

IGT equation:

$$Q\ (m^3/d) = 1.2822x10^{-3}E\left(\frac{T_b}{P_b}\right)\left(\frac{p_1^2 - e^s p_2^2}{G^{0.8}T_fL\mu^{0.2}}\right)^{0.555} D^{2.667} \tag{4.11}$$

4.1.4 Hydrogen Compression

After having calculated the pressure drop of the hydrogen gas flowing inside the NGT pipeline between the starting and ending points, given the fact that a pressure higher than 50 bar is required at the shore, the modelling of the compressor unit can be achieved. As already mentioned, the compression level should be adequate so that hydrogen is capable of reaching the shore at the required pressure level, also taking into account the pressure drop. More specifically, the compressor modelling mainly includes calculating the compression power required (kW), which is achieved with equation 4.12 (André et al., 2014; Guidehouse & Berenschot, 2021; van Schot & Jepma, 2020):

$$\mathrm{P\ (kW)} = \frac{\mathrm{Q}}{3600 \cdot 24 \cdot \mathrm{HHV_{H_2}}} \cdot \frac{\mathrm{Z \cdot T \cdot R}}{\mathrm{M_{H_2}} \cdot \eta_{\mathrm{comp}}} \cdot \frac{\mathrm{N_\gamma}}{\gamma - 1} \cdot \left[\left(\frac{\mathrm{P_{out}}}{\mathrm{P_{in}}} \right)^{\frac{\gamma-1}{\mathrm{N_\gamma}}} - 1 \right] \tag{4.12}$$

Where Q (kWh/d) is the hydrogen's flow rate inside the pipeline (considering the HHV of hydrogen: 39.4 kWh/kg), Z (dimensionless) is the compressibility factor of H_2, T (K) is the compressor temperature, R ($J \cdot K^{-1} mol^{-1}$) is the ideal gas universal constant, $\mathrm{M_{H_2}}$ ($g \cdot mol^{-1}$) is hydrogen's molecular mass, η_{comp} (dimensionless) is the isentropic efficiency of the compressor, taken as 88% according to the National Renewable Energy Laboratory (NREL) estimation for reciprocating compressors with a maximum capacity of about 16 MW (M. A. Khan et al., 2021), $\mathrm{N_\gamma}$ is the number of compression stages required, γ (dimensionless) is the diatomic constant factor, $\mathrm{P_{in}}$ is the suction pressure (inlet), and $\mathrm{P_{out}}$ is the discharge pressure (outlet) (van Schot & Jepma, 2020) The values of the aforementioned parameters can be found in Table 4.4. The value of $\mathrm{P_{out}}$ in this case is known, as it is equal to the pressure hydrogen will enter the pipeline at – calculated in the previous step.

Determining the optimal number of compression stages necessary strongly depends on the compression ratio value. Compression ratio (dimensionless) is the ratio of outlet, $\mathrm{P_{out}}$, to inlet pressure, $\mathrm{P_{in}}$, as can be seen in equation 4.13. Typically, for compression ratio values between 1 and 3, single stage compression is preferred, and for higher compression ratios multi-stage compression is more suitable.

$$\text{Compression Ratio} = \frac{\mathrm{P_{out}}}{\mathrm{P_{in}}} \tag{4.13}$$

Regarding the compressibility factor (Z), which is a key thermodynamic characteristic of gases, indicating the divergence of a real gas behaviour from an ideal gas behaviour, it is estimated to have a value of 1.03 for average temperature and pressure conditions examined in this study (T=298 K, P=50 bar). This is based on public data provided by the National Institute of Standards and Technology (NIST) and is also verified by the graph of Figure 4.3, which depicts the compressibility factors for various gases for different pressures.

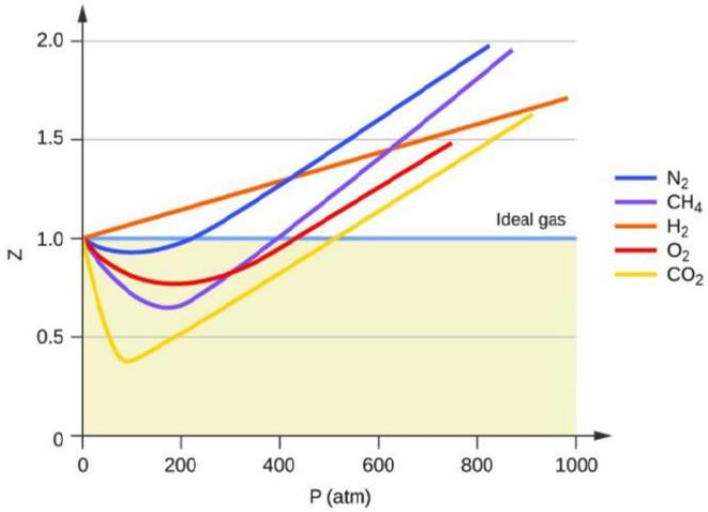

Figure 4.3: Compressibility factor (Z) vs pressure at 273 K, for several gases

After having calculated the actual compressor power, the rated compressor power (kW) can also be found through equation 4.14 (M. A. Khan et al., 2021):

$$\text{Rated Compressor Power (kW)} = \frac{\text{Actual Compressor Power}}{\text{Motor Efficiency}} \tag{4.14}$$

Where the actual compressor power (kW) is the result of equation 4.12. The motor efficiency in this analysis is assumed to be 95%, considering an electric motor to drive the compressor (M. A. Khan et al., 2021). The total number of compressors needed is calculated by dividing the rated compressor power by the maximum compressor capacity for a single unit (~16 MW).

For the needs of calculating the compression energy requirement, we assume 8,760 full-load hours per year. However, it needs to be noted that the effect of the variable hydrogen input on the compressor's efficiency is not taken into account. The yearly energy requirements of the compression are calculated by equation 4.15, as can be seen below. Table 4.6 presents the main assumptions regarding the compressors used in this study.

$$\text{Compression Energy Requirement (kWh/y)} = \text{Rated Comp. Power} \cdot \text{Full–load hours} \tag{4.15}$$

Table 4.6: Main assumptions used for the compressor modelling

Compressor Type	Reciprocating	-
Motor Efficiency	95	%
Isentropic Efficiency	88	%

4.2 Economic Analysis

After having calculated the technical aspect of hydrogen transportation via pipeline, a cost analysis of the key system components is also performed. Specifically, the analysis will be focusing on the hydrogen transportation part of the system, including hydrogen compression and pipeline cost evaluation. This part of the study will help answer the final research sub-question: What is the levelized cost of hydrogen (LCOH) delivered at the shore? It should be noted that cost analysis of the offshore wind turbines and electrolysis components is not included, as it is out of the scope of this study.

The levelized cost of hydrogen transport (hereafter referred to as $LCOH_{system}$), according to equation 4.16, is comprised of the levelized cost of hydrogen compression and the levelized cost of the hydrogen pipeline:

$$\mathrm{LCOH_{system}}(€/\mathrm{kg_{H_2}}/1000\ \mathrm{km}) = \mathrm{LCOH_{comp}} + \mathrm{LCOH_{pipe}} \tag{4.16}$$

Where $LCOH_{comp}$ refers to the levelized cost of compression (€/kg_{H_2} /1000 km) and $LCOH_{pipe}$ is the levelized cost of the hydrogen pipeline (€/kg_{H_2} /1000 km).

Therefore, the economic analysis can be divided into two separate parts: Compression cost analysis and pipeline cost analysis, as will be described in the following sections.

4.2.1 Hydrogen Compression Cost Analysis

Hydrogen compression constitutes the greatest part of the overall hydrogen delivery cost, if manufacturing expenses are not taken into account, especially when repurposed natural gas pipeline utilization is examined (Parks et al., 2014). A compressor's purchasing cost might range from a few thousands to millions of euros, based on its size and desired compression ratio. Hence, compression typically needs to be performed at large scale in order to compensate for this expense (M. A. Khan et al., 2021).

Calculating the $LCOH_{comp}$ first requires the calculation of the compressor's capital expenditures ($CAPEX_{comp}$), its fixed operational expenses ($OPEX_{comp}$), as well as the energy (electricity) cost for its operation (powering the compressor electric motor), as can be seen in equation 4.17. More details on the calculation of $CAPEX_{comp}$, $OPEX_{comp}$, and electricity costs can be found below.

$$\mathrm{LCOH_{comp}}(€/\mathrm{kg_{H_2}}/1000\ \mathrm{km}) = \mathrm{CAPEX_{comp}} + \mathrm{OPEX_{comp}} + \mathrm{Electricity\ Cost} \tag{4.17}$$

Capital Cost of Hydrogen Compression ($CAPEX_{comp}$)

The calculation of the capital expenditures of the hydrogen compressor, is mainly based on assumptions made by van Schot & Jepma (2020). Specifically, the capital cost of compression is calculated based on the required compression power and is assumed to amount to 2,000,000 €/MW. This is also referred to as Total Capital Investment (TCI), meaning the initial capital outlay which may take place over a number of years, based on how complex the project procedure is (M. A. Khan et al., 2021). Generally, the compressor costs are quite uncertain since other sources include different $CAPEX_{comp}$ values, and therefore, a sensitivity analysis is done to determine how this affects the LCOH transport, as will be explained in Section 5.3. For this study, the assumption followed is made by van Schot & Jepma, (2020), who analyse the hydrogen potential in the North Sea. The $CAPEX_{comp}$ value is also verified by the 31 gas TSO's constituting the European Hydrogen Backbone, according to which the assumed $CAPEX_{comp}$ is 2,200,000 €/MW (minor difference), corroborating the initial assumption.

The total capital investment typically takes place at the start of the project's lifespan. In order for it to be comparable to other expenses occurring on a yearly basis, as for example the compressor's fixed yearly operating expenses and the yearly electricity costs, the annualized $CAPEX_{comp}$ (€/y) is introduced, as can be seen in equation 4.18:

$$\text{Annualized CAPEX}_{\text{comp}}\ (€/\text{y}) = \text{CAPEX}_{\text{comp}} \cdot \text{Capital recovery factor (CRF)} \tag{4.18}$$

Where $CAPEX_{comp}$ is expressed in €, and the capital recovery factor (dimensionless) is being calculated according to equation 4.19:

$$\text{CRF} = \frac{\text{i}\,(1+\text{i})^{\text{n}}}{(1+\text{i})^{\text{n}}-1} \tag{4.19}$$

Where i (%) is the discount rate (also referred to as the weighted average cost of capital – WACC), and n is the assumed lifetime of the compressor (y). The assumed values can be found in Table 4.7.

Finally, the total $CAPEX_{comp}$ can be also expressed in terms of the hydrogen throughput (€/kgH_2). This is calculated according to equation 4.20:

$$\text{CAPEX}_{\text{comp}}\ (€/\text{kg}_{\text{H}_2}) = \frac{\left(\text{Annualized CAPEX}_{\text{comp}}\right)}{(\text{Availability}\ \cdot \text{Design Capacity}\ \cdot\ 365)} \tag{4.20}$$

Where the availability (%) term refers to the percentage of the year that the compressor will be operating. This is influenced by the time the compressor is required to be offline for maintenance (M. A. Khan et al., 2021). The design capacity (kgH_2/d) term refers to the hydrogen throughput, which is equal to the hydrogen mass flowrate, Q. The division with 365 (d/y) takes place to express the result on a yearly basis.

Having calculated the $CAPEX_{comp}$ in terms of €/kgH_2, the result can also be expressed on a per 1,000 km transported basis, using that distance as a reference point for having comparable results with other studies (for example, the European Hydrogen Backbone publications). The new $CAPEX_{comp}$ (€/kgH_2/1000 km) is calculated according to equation 4.21:

$$\text{CAPEX}_{\text{comp}}\ (€/\text{kg}_{\text{H}_2}/1000\ \text{km}) = \frac{\left(\ \text{CAPEX}_{\text{comp}}\right)\cdot 1000}{(\text{Pipeline Length})} \tag{4.21}$$

Operating Cost of Hydrogen Compression ($OPEX_{comp}$)

After having calculated the capital investment cost for the compressor, the fixed operating expenses ($OPEX_{comp}$) can also be calculated. This is done based on the assumption that the $OPEX_{comp}$ are equal to a percentage (1.7%) of the $CAPEX_{comp}$, according to the European Hydrogen Backbone, (2022), as can be seen in equation 4.22. The $OPEX_{comp}$ (€/y) are mainly including fixed Operations and Maintenance (O&M) costs as well as labour costs, but no electricity costs which are calculated separately, as can be seen below. Other literature sources assume similar values for the $OPEX_{comp}$, (excluding electricity costs), such as the Council of European Energy Regulators & SUMICSID, (2019) assuming 3% and van Schot & Jepma, (2020) assuming 2% of the corresponding $CAPEX_{comp}$. A sensitivity analysis was also done to reflect on the uncertainty around this assumption, as well as determine how it affects the end result, as can be seen in Section 5.3.

$$\mathrm{OPEX_{comp}}\ (€/\mathrm{y}) = 1.7\ \%\ \mathrm{CAPEX_{comp}} \tag{4.22}$$

Similar to the $CAPEX_{comp}$ calculations, the $OPEX_{comp}$ can be expressed in terms of hydrogen throughput (€/kgH_2), according to equation 4.23, and in terms of (€/kgH_2/1000km), according to equation 4.24. The availability, design capacity, and pipeline length terms are taken similar to the $CAPEX_{comp}$ calculations presented in the previous section.

$$\mathrm{OPEX_{comp}}\ (€/\mathrm{kg_{H_2}}) = \frac{(\mathrm{OPEX_{comp}})}{(\mathrm{Availability}\ \cdot \mathrm{Design\ Capacity}\ \cdot\ 365)} \tag{4.23}$$

$$\mathrm{OPEX_{comp}}(€/\mathrm{kg_{H_2}}/1000\ \mathrm{km})\ = \frac{(\ \mathrm{OPEX_{comp}}) \cdot 1000}{(\mathrm{Pipeline\ Length})} \tag{4.24}$$

Electricity Cost for Hydrogen Compression

After having calculated both the $CAPEX_{comp}$ and $OPEX_{comp}$, the remaining part of the $LCOH_{comp}$ calculation (as expressed in equation 4.17) is the electricity (energy) requirements for the hydrogen compression. As mentioned earlier, this electricity is used to power the compressor's electric motor, its cost (€/y) is a variable operating expenditure (hence not included in the fixed $OPEX_{comp}$ computation), and its calculation can be achieved with equation 4.25 (M. A. Khan et al., 2021):

$$\mathrm{Electricity\ Cost}\ (€/\mathrm{y}) = \mathrm{Compressor\ Rated\ Power} \cdot \mathrm{Operating\ hours}\ \cdot \mathrm{Electricity\ price} \tag{4.25}$$

Where the compressor rated power (kW) is calculated by equation 4.14, the compressor operating hours are taken as 8,760 h/y, and the electricity price is assumed to be 0.04 €/kWh, according to Miralda van Schot and Catrinus Jepma, (2020) estimation for renewable electricity produced by offshore wind turbines in the North Sea.

In order to calculate the electricity costs in terms of hydrogen throughput (€/kgH_2), equation 4.26 is utilized:

$$\text{Electricity}_{\text{comp}}\ (€/\text{kg}_{\text{H}_2}) = \frac{(\text{Electricity Cost})}{(\text{Availability} \cdot \text{Design Capacity} \cdot 365)} \tag{4.26}$$

Where Electricity Cost (€/y) is calculated by equation 4.25, and the terms in the denominator are similar to equations 4.20 and 4.23. Finally, equation 4.27 can be used to calculate the energy required for compression in terms of €/kgH_2/1000 km.

$$\text{Electricity}_{\text{comp}}(€/\text{kg}_{\text{H}_2}/1000\ \text{km}) = \frac{(\text{Electricity}_{\text{comp}}) \cdot 1000}{(\text{Pipeline Length})} \tag{4.27}$$

The main assumptions and other inputs for the compressor cost modelling are also summarized in Table 4.7:

Table 4.7: Main assumptions and values used as inputs for developing the compressor cost model (André et al., 2014; European Hydrogen Backbone, 2022; M. A. Khan et al., 2021; van Schot & Jepma, 2020)

Parameter	Value	Unit
CAPEX Compression	2	M€/MW
OPEX Compression	1.7	% of CAPEX
Compressor Lifetime	25	y
Pipeline Length	253.2	km
Pipeline Diameter	36	inch
Compressor Isentropic Efficiency	88	%
Discount Rate (WACC)	5	%
Electricity Price	40	€/MW

4.2.2 Hydrogen Pipeline Transportation Cost Analysis

Calculating the $LCOH_{pipe}$ first requires the calculation of the pipeline's capital expenditures ($CAPEX_{pipe}$) as well as its operational expenses ($OPEX_{pipe}$), as can be seen in equation 4.28 (applicable to both new and repurposed hydrogen pipelines). Contrary to the compression cost calculations, here there are no electricity costs involved.

$$\text{LCOH}_{\text{pipe}}(€/\text{kg}_{\text{H}_2}/1000\ \text{km}) = \text{CAPEX}_{\text{pipe}} + \text{OPEX}_{\text{pipe}} \tag{4.28}$$

Where $CAPEX_{pipe}$ and $OPEX_{pipe}$ are also expressed in $(€/kg_{H_2}/1000\ km)$. The methodology followed for calculating the levelized cost of repurposed pipelines for hydrogen transportation requires to first calculate the capital expenditures for a newly developed hydrogen pipeline with the same diameter. According to ACER, (2021) and the European Hydrogen Backbone, (2022), the CAPEX of offshore repurposed pipelines ($CAPEX_{pipe-Rep}$) is assumed to be 10% of the CAPEX of newly developed hydrogen pipelines ($CAPEX_{pipe-New}$). During an interview with the NGT pipeline operators, they also confirmed that the 10% assumption for the $CAPEX_{pipe-Rep}$ is reasonable (R. Hagen, M. Ros, personal communication, October 11, 2022). Even though there is still uncertainty regarding the cost of repurposing gas pipelines for hydrogen transport since it is a new practice, the cost is expected to be quite low. The main activities generally required in order for a gas pipeline to be repurposed (included in the 10%) are the following: Cleaning the pipeline from the contained natural gas in order for pure hydrogen to be transported, performing a detailed initial inline inspection to locate any microcracks on the pipeline walls to ensure that hydrogen will not enter the metal framework resulting in embrittlement, as well as changing all side taps and valves along the pipeline, to be compatible with hydrogen. Nevertheless, as explained in Section 3.4.1, changing the side taps and valves will not be needed in the NGT case, according to the details of the 'Certificate of Fitness' acquired by Bureau Veritas in October 2022, which would lead to an even lower capital cost. In fact, according to the NGT operators, the CAPEX of repurposing the NGT pipeline could be even less than 10% of the CAPEX of developing a new pipeline, as there are very few costly activities involved. However, since the uncertainty is still high, and some sources state that $CAPEX_{pipe-Rep}$ could reach up to 35% of the $CAPEX_{pipe-New}$, a sensitivity analysis is also done to determine how the repurposing cost affects the overall LCOH transport. More details concerning the sensitivity analysis can be found in Section 5.3.

Regarding the $OPEX_{pipe}$, these are assumed to have the same value, for both new and repurposed pipelines. Therefore, for the needs of this study two different $LCOH_{pipe}$ need to be calculated: $LCOH_{pipe-New}$ and $LCOH_{pipe-Rep}$, according to equations 4.29 and 4.30, which are derived from 4.28:

$$\mathrm{LCOH_{pipe-New}}\ (€/\mathrm{kg_{H_2}}/1000\ \mathrm{km}) = \mathrm{CAPEX_{pipe-New}} + \mathrm{OPEX_{pipe}} \tag{4.29}$$

$$\mathrm{LCOH_{pipe-Rep}}\ (€/\mathrm{kg_{H_2}}/1000\ \mathrm{km}) = 10\% \cdot \mathrm{CAPEX_{pipe-New}} + \mathrm{OPEX_{pipe}} \tag{4.30}$$

Capital Cost of NEW Hydrogen Pipeline: ($CAPEX_{pipe-New}$)

The calculation of the capital expenditures of a newly built hydrogen pipeline ($CAPEX_{pipe-New}$), is mainly founded on assumptions made by Guidehouse & Berenschot, (2021), Miralda van Schot and Catrinus Jepma, (2020), and Spyroudi et al., (2020), for offshore new hydrogen pipeline development in the North Sea. More specifically, the capital expenditure of a new pipeline is based on the pipeline diameter, as well as its length, and is assumed to be 45 k€/inch/km. According to input provided by NGT, this assumption is considered to be reasonable, although a sensitivity analysis will also be performed in Section 5.3 to investigate how this affects the end result. The annualized $CAPEX_{pipe-New}$ (€/y) is also calculated in order for it to be comparable to other expenses occurring on a yearly basis, as can be seen in equation 4.31:

$$\text{Annualized CAPEX}_{\text{pipe}-\text{New}}\ (€/\text{y}) = \text{CAPEX}_{\text{pipe}-\text{New}} \cdot \text{Capital recovery factor (CRF)} \tag{4.31}$$

The capital recovery factor is calculated according to equation 4.19, taking into consideration the WACC and the assumed lifetime of the pipeline. The assumed values can be found in Table 4.8.

The total $CAPEX_{pipe - New}$ can be also expressed per kilogram hydrogen flowing through the pipeline (€/kgH_2), as can be seen in equation 4.32:

$$\text{CAPEX}_{\text{pipe}-\text{New}}\ (€/\text{kg}_{\text{H}_2}) = \frac{(\text{Annualized CAPEX}_{\text{pipe}-\text{New}})}{(\text{Availability} \cdot \text{Design Capacity} \cdot 365)} \tag{4.32}$$

Where the availability (%) and design capacity (kgH_2/d) terms are similar to the ones used in equation 4.20. Having calculated the $CAPEX_{pipe - New}$ in terms of €/kgH_2, the result can also be expressed on a 1,000 km transported basis (€/kgH_2/1000 km), as can be seen in equation 4.33:

$$\text{CAPEX}_{\text{pipe}-\text{New}}\ (€/\text{kg}_{\text{H}_2}/1000\ \text{km}) = \frac{(\text{CAPEX}_{\text{pipe}-\text{New}}) \cdot 1000}{(\text{Pipeline Length})} \tag{4.33}$$

Capital Cost of REPURPOSED Hydrogen Pipeline: ($CAPEX_{pipe - Rep}$)

After completing the CAPEX calculations for offshore new hydrogen pipelines, the CAPEX of existing repurposed natural gas pipelines (which is the case for the present study) can be also calculated. As explained earlier, the $CAPEX_{pipe - Rep}$ are assumed to be equal to 10% of the $CAPEX_{pipe - New}$, as can be seen in equation 4.34:

$$\text{CAPEX}_{\text{pipe}-\text{Rep}}\ (€/\text{kg}_{\text{H}_2}/1000\ \text{km}) = 10\% \cdot \text{CAPEX}_{\text{pipe}-\text{New}} \tag{4.34}$$

Accordingly, the rest of the $CAPEX_{pipe - New}$ calculations presented in the previous section (annualized CAPEX (€/y), CAPEX (€/kgH_2), and CAPEX (€/kgH_2/1000 km), can also be converted to $CAPEX_{pipe - Rep}$ by multiplying the resulting values with a 10% factor.

Operating Cost of Hydrogen Pipeline ($OPEX_{pipe}$)

After having calculated the capital investment cost for both new and repurposed pipelines, the operating expenses ($OPEX_{pipe}$) can also be calculated. Similar to the compression operating costs calculation methodology, the $OPEX_{pipe}$ (€/y) are expressed as a percentage of the $CAPEX_{pipe - New}$. Specifically, according to European Hydrogen Backbone, (2022), the $OPEX_{pipe}$ values range between 0.8% and 1.0% of the $CAPEX_{pipe - New}$. Based on input provided by NGT in an interview (R. Hagen, M. Ros, personal communication, October 11, 2022), this percentage mainly includes regular inspections, monitoring of the pipeline, and other costs related to seabed changes and conditions (e.g., reburial of pipelines, increasing the seabed height when there is erosion falling off the pipeline walls, by filling the area with sand or gravel). However, since transporting hydrogen in a repurposed pipeline is still a new practice, the $OPEX_{pipe}$ are expected to be toward the high end of the range. According to the NGT operators, the higher operating expenses would be attributed to a quite more intense pipeline monitoring program, and additional inline inspections. NGT's certification exercise indicated that the existing side taps and valves along the pipeline need to be regularly monitored. Furthermore, internal monitoring needs to also take place, to confirm that there are no microcracks developing in the pipeline walls. Therefore, in this study the $OPEX_{pipe}$ are assumed to be 1.0% of the $CAPEX_{pipe-New}$, as can be seen in equation 4.35. Since the uncertainty around the costs of repurposing natural gas pipelines is still high, a sensitivity analysis is also performed to determine how the $OPEX_{pipe}$ assumption affects the end result, as can be seen in Section 5.3.

$$\mathrm{OPEX_{pipe}}\ (€/\mathrm{y}) = 1.0\ \%\ \mathrm{CAPEX_{pipe-New}} \tag{4.35}$$

Similar to the $CAPEX_{pipe}$ calculations, the $OPEX_{pipe}$ can be expressed in terms of hydrogen throughput (€/kgH_2), according to equation 4.36, and in terms of (€/kgH_2/1000 km), according to equation 4.37. The availability and design capacity terms are taken similar to the $CAPEX_{comp}$ calculations.

$$\mathrm{OPEX_{pipe}}(€/\mathrm{kg_{H_2}}) = \frac{(\mathrm{OPEX_{pipe}})}{(\mathrm{Availability} \cdot \mathrm{Design\ Capacity} \cdot 365)} \tag{4.36}$$

$$\mathrm{OPEX_{pipe}}(€/\mathrm{kg_{H_2}}/1000\ \mathrm{km}) = \frac{(\mathrm{OPEX_{pipe}}) \cdot 1000}{(\mathrm{Pipeline\ Length})} \tag{4.37}$$

The main assumptions and other inputs used for the pipeline cost modelling are also summarized in Table 4.8:

Table 4.8: Main assumptions and values used as inputs for developing the pipeline cost (European Hydrogen Backbone, 2022; NGT, 2022; Spyroudi et al., 2020; van Schot & Jepma, 2020)

Parameter	Value	Unit
CAPEX Pipeline	45	k€/inch/km
OPEX Pipeline	1	% of CAPEX
Pipeline Lifetime	40	y
Pipeline Length	253.2	km
Pipeline Availability	99.8	%

5

Results

In this chapter the results of the system modelling will be presented. These will be divided in technical and economic results. Special focus will be placed on the system's key parts: hydrogen compression and transportation via the NGT pipeline.

5.1 Technical Results

Since offshore wind is an intermittent source of energy, the exact output for any given moment cannot be predicted. Therefore, for simplicity the technical analysis is broken down into two main scenarios, according to the energy output of the wind turbines in search areas 7 and 3. Specifically, the average (operating) flow scenario represents an average energy output, corresponding to an operation of 5,000 h/y, and the maximum flow scenario represents the maximum energy output case, in which all 10 GW of offshore wind search areas 7 and 3 are being converted to hydrogen. The maximum flow scenario is utilized for sizing the compressor: calculations were performed for the maximum flow rate case, in order to be able to accommodate the full 10 GW of wind converted into hydrogen.

5.1.1 Average (Operating) Flow Scenario

This scenario reflects the average (operating) flow of hydrogen through the NGT pipeline. Starting from the energy generation from the offshore wind turbines, with a total capacity of 10 GW and an assumed capacity factor of 5,000 load hours per year, the energy input for the electrolyzer is calculated. As explained in Chapter 4, 99.5% of the generated electricity is assumed to be powering the electrolysis unit and the remaining 0.5% is assumed to be used for hydrogen compression, treatment, seawater desalination, and other minor electricity needs of the system. The results, expressed in different units are presented in Table 5.1:

Table 5.1: Electricity generated by the wind turbines of search areas 7 & 3, distributed among the electrolysis unit for H_2 production (99.5%) and to other system's electricity needs (0.5%), for the operating flow scenario

Electricity Input for Electrolysis (99.5%)		**Other (0.5%)**	
49.75	TWh/y	0.25	TWh/y
136.30	GWh/d	0.72	GWh/d

Regarding the electrolysis part of the system, the produced green hydrogen flow rate results, in terms of mass, volume, and energy (HHV) for the operating flow scenario are presented in Table 5.2, expressed in various units. The volumetric flow results are calculated based on hydrogen density at NTP conditions (0.08375 kg/m^3). The average hydrogen transport capacity for this scenario is found to be approximately 4.5 GW. The maximum capacity needed can also be calculated by multiplying the entire 10 GW of offshore wind with the electrolyzer efficiency on HHV (78.8%), resulting in approximately 7.9 GW.

Table 5.2: Hydrogen flow rates, expressed in mass, volume, and energy (HHV) units, corresponding to the operating flow scenario

114	ton/h
32	kg/s
2,726	ton/d
377	Nm^3/s
39	TWh/y (HHV)
107	GWh/d (HHV)
141	PJ/y

<u>Pressure Drop Calculation:</u>

After hydrogen is produced by electrolysis, the next stage of the examined system is hydrogen compression, in order to enable it to travel through the NGT pipeline and reach the shore. As explained in Chapter 4, in order to calculate the compressor's power as well as its outlet pressure, the pressure drop (ΔP) along the NGT pipeline needs to be found. This was achieved by using the Darcy Weisbach equation with the condition that hydrogen should reach the shore with a pressure above 50 bar. Specifically, the 253.2 km long NGT pipeline was broken down into 10 m intervals, calculating the respective pressure loss (bar), gas velocity (m/s), and gas density (kg/m^3) for each interval. The starting point of the calculation (initial pressure level) was first assumed as 80 bar, which resulted in an end pressure of 71.8 bar (ΔP = 8.2 bar). Through trial and error, by adjusting the initial pressure, so that the end pressure remains above 50 bar, the final pressure drop results were obtained, as can be seen in Table 5.3:

Table 5.3: Initial pressure, final pressure, and pressure drop final results, as calculated for the average flow scenario, according to the Darcy Weisbach equation

Initial Pressure	65.00	bar
Final Pressure	54.65	bar
Pressure Drop	10.35	bar

The calculated pressure drop value is in accordance with González Díez et al., (2020), who estimated a typical pressure drop between 3 and 10 bar per 100 km for North Sea pipeline applications (the present analysis resulted in ~4 bar/100 km). The pressure drop calculations indicate that there is no need for recompression at an intermediary point of the pipeline, since the initial compression is sufficient for the hydrogen to reach the shore. Figures 5.1 – 5.3 depict how the pressure, gas velocity, and density change with distance travelled (equal to pipeline length), according to the pressure drop model developed for this study.

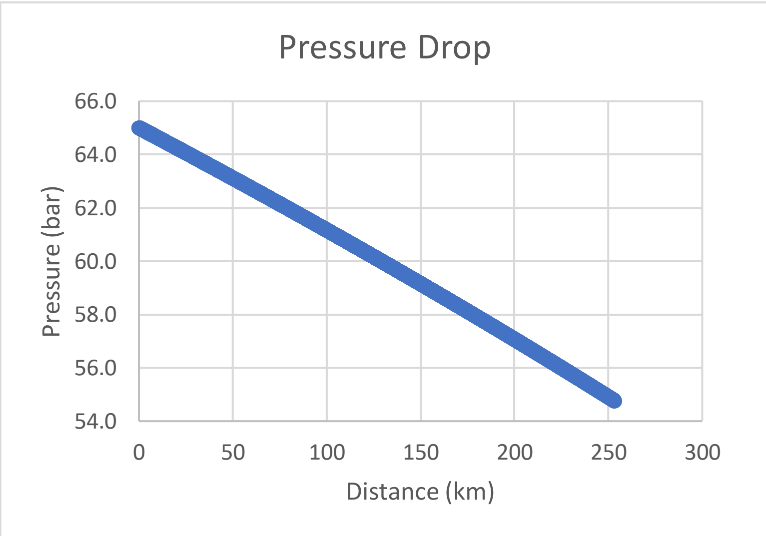

Figure 5.1: Hydrogen pressure (bar) vs Distance (km) for the operating flow scenario

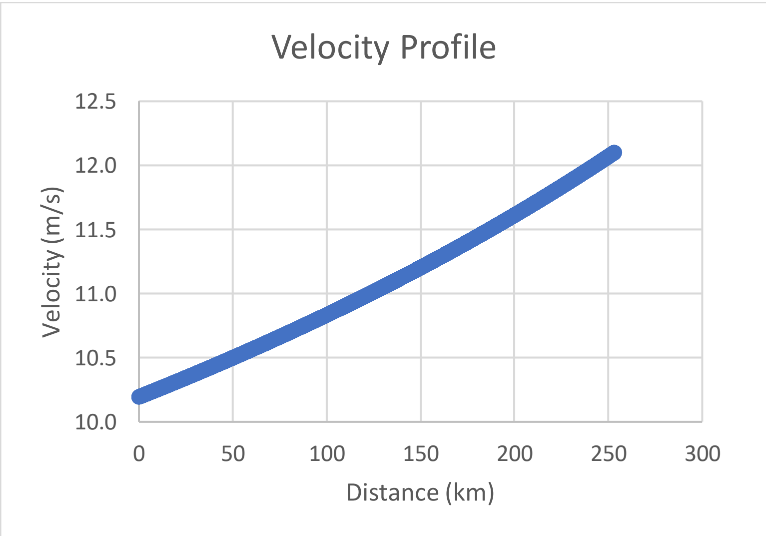

Figure 5.2: Hydrogen velocity (m/s) vs Distance (km) for the operating flow scenario

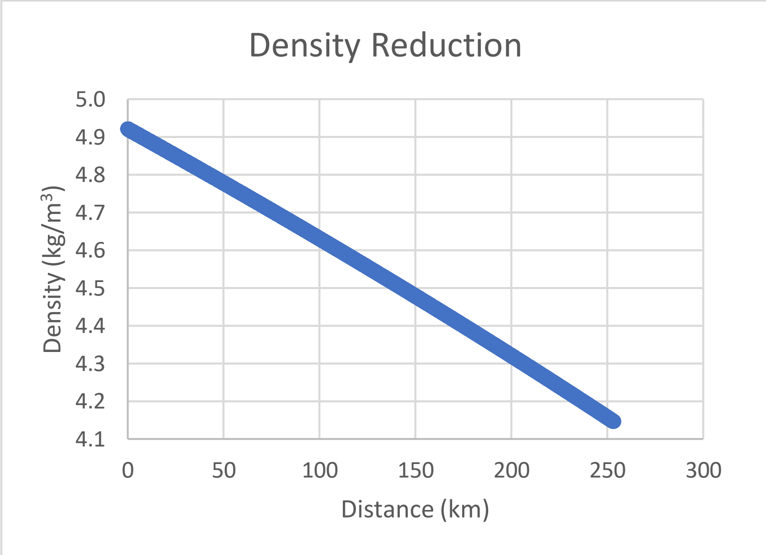

Figure 5.3: Hydrogen density (kg/m³) vs Distance (km) for the operating flow scenario

In order for the pressure drop calculation to be performed according to Darcy Weisbach equation, first the friction factor should be calculated. This is achieved by the Moody Diagram (Figure 4.2), using as an input the Reynolds number for hydrogen flow though the NGT pipeline (which is computed according to equation 4.6). Both the friction factor and Reynolds number values are presented in Table 5.4 (dimensionless). The calculated Reynolds number (Re = $5.07 \cdot 10^6$) indicates that the hydrogen flow inside the pipeline is turbulent.

Table 5.4: Reynolds number and friction factor calculated for the average (operating) flow of hydrogen through the NGT pipeline

Reynolds Number	$5.07 \cdot 10^6$
Friction Factor	0.013

Having calculated the pressure drop and the initial pressure for hydrogen in NGT pipeline, the actual compressor power as well as the rated compressor power for the operating flow scenario can also be calculated, according to equations 4.12 and 4.14 respectively. These values will be used for the compression electricity requirement calculation. The results are presented in Table 5.5:

Table 5.5: Actual compressor power and rated compressor power results, according to the average (operating) flow scenario

Actual Compressor Power	43.7	MW
Rated Compressor Power	44.6	MW

5.1.2 Maximum Flow Scenario

The maximum flow scenario represents the maximum energy output case, according to which all 10 GW of offshore wind search areas 7 and 3 are being converted to hydrogen. This analysis is mainly done for determining the compressor size, since it needs to be able to accommodate the full 10 GW of wind converted into hydrogen. Similar to the operation flow scenario, 99.5% of the generated offshore wind electricity is assumed to be powering the electrolysis unit and the remaining 0.5% is assumed to be used for hydrogen compression, treatment, seawater desalination, and other minor electricity needs of the system. The results, expressed in different units are presented in Table 5.6:

Table 5.6: Electricity generated by the wind turbines of search areas 7 & 3, distributed among the electrolysis unit for H_2 production (99.5%) and to other system's electricity needs (0.5%), for the maximum flow scenario

Electricity Input for Electrolysis (99.5%)		**Other (0.5%)**	
87.16	TWh/y	0.44	TWh/y
238.80	GWh/d	1.20	GWh/d

Concerning the electrolysis part of the system, the produced green hydrogen flow rate results, in terms of mass, volume, and energy (HHV) for the maximum flow scenario are presented in Table 5.7, expressed in various units. The volumetric flow results are calculated based on hydrogen density at NTP conditions (0.08375 kg/m^3). The corresponding hydrogen transport capacity for this scenario is found to be approximately 7.9 GW.

Table 5.7: Hydrogen flow rates, expressed in mass, volume, and energy (HHV) units, corresponding to the maximum flow scenario

199	ton/h
55	kg/s
4,776	ton/d
660	Nm^3/s
69	TWh/y (HHV)
188	GWh/d (HHV)
247	PJ/y

Regarding the pressure drop calculation, for determining the initial pressure in the NGT pipeline, this was achieved by using the Darcy Weisbach equation with the condition that hydrogen should reach the shore with a pressure above 50 bar, similar to the operating flow scenario calculation. Again, the 253.2 km NGT pipeline was divided into 10 m intervals, calculating the respective pressure loss (bar), gas velocity (m/s), and gas density (kg/m^3) for each interval. Through trial and error, by adjusting the initial pressure, so that the end pressure remains just above 50 bar, the final pressure drop results were obtained, as can be seen in Table 5.8.

Table 5.8: Initial pressure, final pressure, and pressure drop final results, as calculated for the maximum flow scenario, according to the Darcy Weisbach equation

Initial Pressure	80	bar
Final Pressure	51	bar
Pressure Drop	29	bar

Figures 5.4 – 5.6 depict how the pressure, gas velocity, and density change with distance travelled (equal to pipeline length) for the maximum flow scenario, according to the pressure drop model developed for this study.

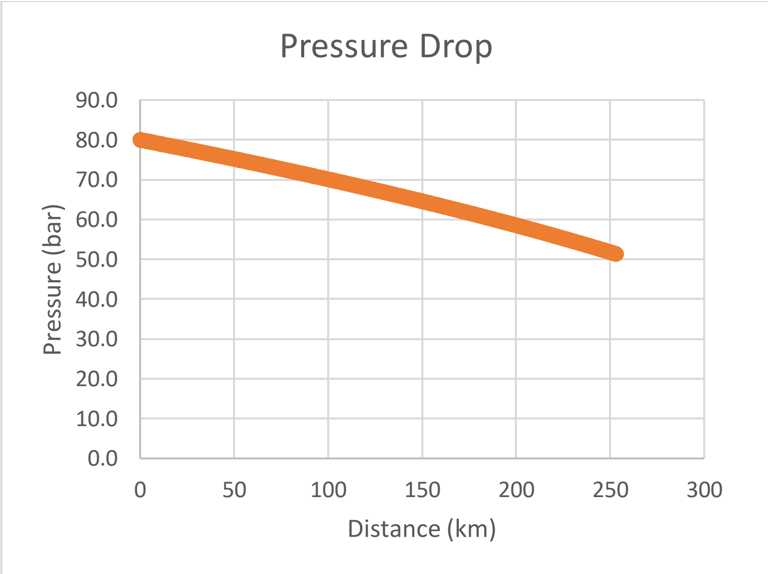

Figure 5.4: Hydrogen pressure (bar) vs Distance (km) for the maximum flow scenario

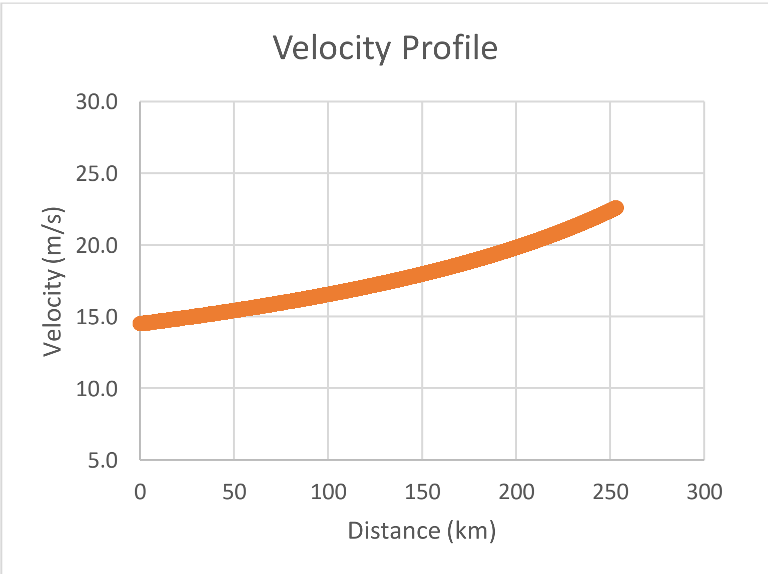

Figure 5.5: Hydrogen velocity (m/s) vs Distance (km) for the maximum flow scenario

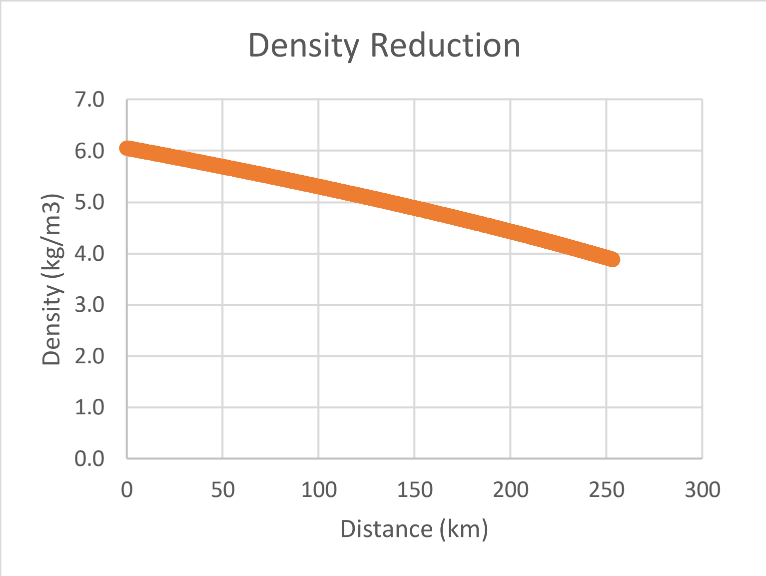

Figure 5.6: Hydrogen density (kg/m³) vs Distance (km) for the maximum flow scenario

Having calculated the pressure drop and the initial pressure for hydrogen in NGT pipeline, the actual compressor power as well as the rated compressor power for the maximum flow scenario can also be calculated, according to equations 4.12 and 4.14 respectively. The rated compressor power calculated for this scenario represents the final compression power, required for handling the whole 10 GW of offshore wind, and therefore corresponds to the actual size the compressor should be sized to. The calculation results are presented in Table 5.9:

Table 5.9: Actual compressor power and rated compressor power results, according to the maximum flow scenario

Actual Compressor Power	100.5	MW
Rated Compressor Power	102.5	MW

Having determined the compressor's total capacity, the number of compressors needed can be calculated, given that the maximum rated power of each compressor is assumed to be approximately 16 MW, as explained in previous parts of this report. Dividing the total rated compressor power with the maximum power for a single compressor, results in a total of 7 compressors for the studied system. The assumed distribution of compressors between the two search areas, as well as each compressor's rated capacity can be found in Table 5.10.

Table 5.10: Compressor distribution between search areas 7 & 3

		Rated Power (Total)	**Rated Power (Per Compressor)**
Total No. of Compressors	7	102.5 MW	-
No. of Compressors S.A. 7	5	82.0 MW	16.4 MW
No. of Compressors S.A. 3	2	20.5 MW	10.3 MW

5.2 Economic Results

Having analysed the technical characteristics of hydrogen transportation via pipeline, showcasing that the proposed system is achievable from a technical perspective, this section of the report will analyze the economic aspect, in order to determine if the presented case study is financially feasible. For that reason, the Levelized Cost of Hydrogen (LCOH) transported to the shore is calculated, according to equation 4.16, as explained in the previous chapter. The economic analysis performed, focuses primarily on the hydrogen compression and the hydrogen transportation via the NGT pipeline. Therefore, the analysis results are also divided in those two parts: Hydrogen compression economic results (5.2.1) and pipeline economic results (5.2.2). Section 5.2.3 presents the modelling results regarding the entire system, including both the compressor and the pipeline economic considerations.

5.2.1 Compressor Economic Results

In this section, the economic results of hydrogen compression will be presented, leading to the calculation of the $LCOH_{comp}$. Starting with the CAPEX of the compression system ($CAPEX_{comp}$), the calculated results, expressed in different units, can be seen in Table 5.11. For the following results, equations 4.18 - 4.21 were used. The model inputs for calculating those results, are presented in Table 4.7. As explained in Section 5.1.2, the compressor capacity used for determining the $CAPEX_{comp}$ is the one corresponding to the maximum hydrogen flow scenario (102.5 MW) in order for the compressor to be able to accommodate the maximum possible hydrogen throughput.

Table 5.11: CAPEX of compression ($CAPEX_{comp}$) for hydrogen transported via the NGT pipeline, expressed in various units

$CAPEX_{comp}$	
205.1	M€
0.81	M€/km
14.5	M€/y
0.015	€/kgH_2
0.061	€/kgH_2/1000 km

Subsequently the fixed $OPEX_{comp}$ are also calculated, according to equations 4.22 – 4.24, using as model inputs the values presented in Table 4.7. The $OPEX_{comp}$ results, expressed in different units, can be seen in Table 5.12.

Table 5.12: OPEX of compression ($OPEX_{comp}$) for hydrogen transported via the NGT pipeline, expressed in various units

$OPEX_{comp}$	
3.5	M€/y
0.004	€/kgH_2
0.015	€/kgH_2/1000 km

Finally, the electricity cost required for the operation of the compressor (powering the electric motor driving the compressor) is also calculated. In order to calculate the compressor's electricity requirement on a yearly basis, the compressor's power according to the operating (average) flow scenario is multiplied with an assumed 8,760 operating hours per year. The main assumptions and other inputs for the electricity cost calculations are can also be found in Table 4.7. The resulting energy need, together with the electricity cost values, expressed in various units, are presented in Table 5.13.

Table 5.13: Compression electricity requirement and electricity cost results, for hydrogen transported via the NGT pipeline, expressed in different units

Compression Electricity Cost		
Electricity Requirement	391	GWh/y
Electricity Requirement	1.5	GWh/y/km
Electricity Cost	15.6	M€/y
Electricity Cost	61.8	k€/y/km
$Electricity_{comp}$	0.017	€/kgH_2
$Electricity_{comp}$	0.065	€/kgH_2/1000 km

A summary of the main economic results for the hydrogen compression can be found in Table 5.14. This includes the overall $LCOH_{comp}$, calculated based on equation 4.17. The chart of Figure 5.7 illustrates the distribution of the $LCOH_{comp}$ between the $CAPEX_{comp}$, the fixed $OPEX_{comp}$, and the compression's electricity cost.

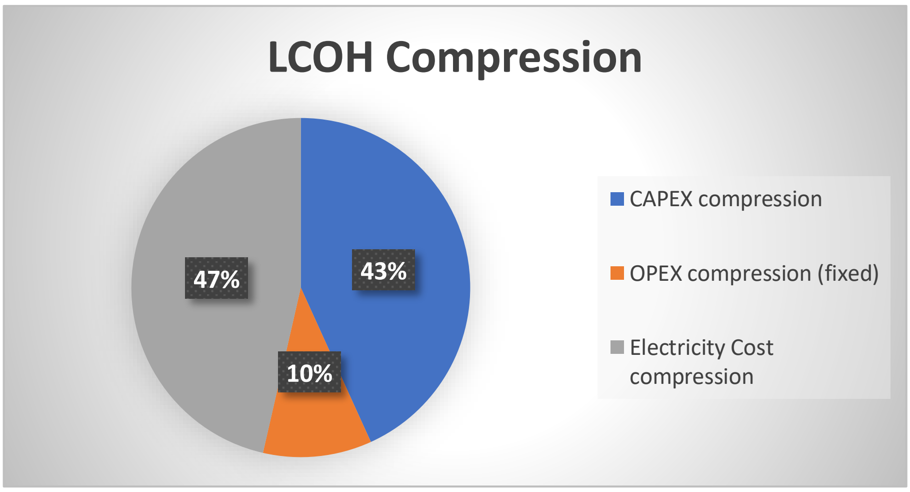

Figure 5.7: Levelized Cost of Hydrogen Compression ($LCOH_{comp}$) distribution between $CAPEX_{comp}$, the fixed $OPEX_{comp}$, and the compression's electricity cost

Table 5.14: Summary of the compression economic results for hydrogen transported through the NGT pipeline

Compression Economic Results		
Cost Parameter	**Value**	**Unit**
	CAPEX	
$CAPEX_{comp}$	205.1	M€
$CAPEX_{comp}$	0.81	M€/km
Annualized $CAPEX_{comp}$	14.6	M€/y
$\underline{CAPEX_{comp}}$	<u>0.061</u>	<u>€/kgH_2 /1000 km</u>
	OPEX (fixed)	
$OPEX_{comp}$	3.49	M€/y
$\underline{OPEX_{comp}}$	<u>0.015</u>	<u>€/kgH_2/1000 km</u>
	Electricity Cost	
Electricity Requirement	391	GWh/y
Electricity Cost	61.8	k€/y/km
$\underline{Electricity_{comp}}$	<u>0.065</u>	<u>€/kgH_2/1000 km</u>
	LCOH Compression	
$LCOH_{comp}$	**0.141**	**€/kgH_2/1000 km**

5.2.2 Pipeline Economic Results

This section will present the economic results regarding the hydrogen transportation via the NGT pipeline. This will lead to the determination of $LCOH_{pipe}$, which will, in addition to the already calculated $LCOH_{comp}$, give the overall $LCOH_{system}$ which is the main objective of this research study. The pipeline economic results will be divided into two parts, according to the calculation methodology explained in Section 4.2.2. Specifically, the economic calculations will be performed for developing a new offshore hydrogen-ready pipeline, as well as for repurposing an existing natural gas pipeline to be used for hydrogen transportation. Therefore, two separate sets of results will be presented: one for the newly developed pipeline cost analysis, leading to the calculation of the $LCOH_{pipe - New}$, and another one for the repurposed pipeline cost analysis, leading to the calculation of the $LCOH_{pipe - Rep}$. The calculation of the economics of a newly developed pipeline is necessary in this analysis, since the capital expenses of a repurposed pipeline of the same diameter are assumed to be a fraction of the capital expenses of the new one, according to equation 4.30.

Starting with the capital cost of a newly developed offshore hydrogen pipeline, the calculated results, expressed in various units, can be seen in Table 5.15. The equations used for the $CAPEX_{pipe - New}$ calculations are 4.31 – 4.33, using as model inputs values of Table 4.8.

Table 5.15: CAPEX of new pipeline ($CAPEX_{pipe\ -\ New}$) : Calculation results, expressed in various units

$CAPEX_{pipe\ -\ New}$	
410.2	M€
1.6	M€/km
23.9	M€/y
0.024	€/kgH_2
0.095	€/kgH_2/1000 km

Similar to the cost calculations for the development of a new hydrogen pipeline, the capital costs of a repurposed pipeline are also calculated and presented in Table 5.16. As explained in Chapter 4.2.2, the $CAPEX_{pipe – Rep}$ are assumed to be equal to 10% of the $CAPEX_{pipe – New}$, according to equation 4.34.

Table 5.16: CAPEX of repurposed natural gas pipeline ($CAPEX_{pipe\ -\ Rep}$) : Calculation results, expressed in various units

$CAPEX_{pipe\ -\ Rep}$	
41.0	M€
0.16	M€/km
2.4	M€/y
0.002	€/kgH_2
0.010	€/kgH_2/1000 km

Next, the pipeline operating cost results are presented in Table 5.17. As described in the previous chapter, the $OPEX_{pipe}$ are calculated as a fraction of the $CAPEX_{pipe – New}$, according to equation 4.35. The model inputs used for these calculations can be found in Table 4.8. It should be noted that the operating costs are assumed to be the same for both newly developed and repurposed pipelines. In practice, there could be a slight difference between the $OPEX_{pipe}$ of new and repurposed pipelines, depending on the requirement to do corrective maintenance over the pipe's lifetime.

Table 5.17: $OPEX_{pipe}$ results, expressed in different units, applicable to both new and repurposed pipelines

$OPEX_{pipe}$	
4.1	M€/y
0.004	€/kgH_2
0.016	€/kgH_2/1000 km

The pipeline cost results, for both new and repurposed pipelines are summarized in Table 5.17. Contrary to the compression economics, there is no electricity costs involved in the pipeline cost results. The cost distribution between the CAPEX and the OPEX for both new and repurposed pipelines can be found in Figures 5.8 and 5.9.

Table 5.18: Summarized pipeline economic results, expressed in different units, for both newly developed and repurposed pipelines

Pipeline Economic Results					
New Pipeline			**Repurposed Pipeline**		
$CAPEX_{pipe}$					
$CAPEX_{pipe-New}$	410.2	M€	$CAPEX_{pipe-Rep}$	41.0	M€
$CAPEX_{pipe-New}$	1.6	M€/km	$CAPEX_{pipe-Rep}$	0.2	M€/km
Annualized $CAPEX_{pipe-New}$	23.9	M€/y	Annualized $CAPEX_{pipe-Rep}$	2.4	M€/y
$\underline{CAPEX_{pipe-New}}$	<u>0.095</u>	<u>€/kgH$_2$/1000 km</u>	$\underline{CAPEX_{pipe-Rep}}$	<u>0.010</u>	<u>€/kgH$_2$/1000km</u>
$OPEX_{pipe}$					
$OPEX_{pipe-New}$	4.1	M€/y	$OPEX_{pipe-Rep}$	4.1	M€/y
Electricity Cost	0	€/km/y	Electricity Cost	0	€/km/y
$\underline{OPEX_{pipe-New}}$	<u>0.016</u>	<u>€/kgH$_2$/1000 km</u>	$\underline{OPEX_{pipe-Rep}}$	<u>0.016</u>	<u>€/kgH$_2$/1000 km</u>
$LCOH_{pipe}$					
$LCOH_{pipe-New}$	**0.111**	**€/kgH$_2$/1000 km**	**$LCOH_{pipe-Rep}$**	**0.026**	**€/kgH$_2$/1000 km**

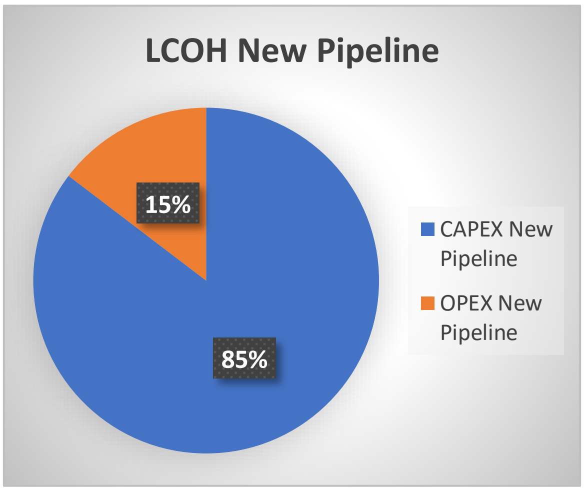

Figure 5.8: Cost distribution between CAPEX and OPEX for newly developed pipelines

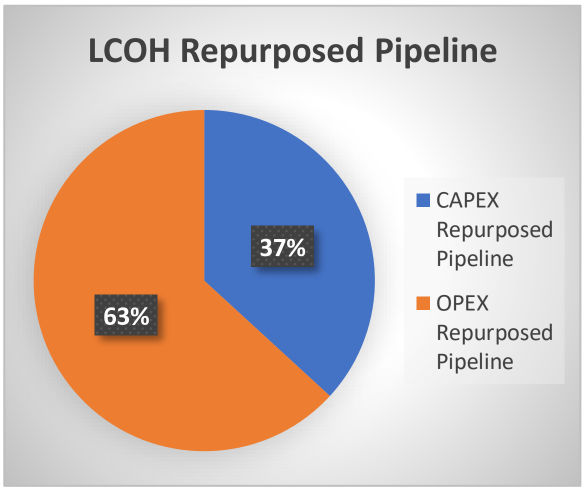

Figure 5.9: Cost distribution between CAPEX and OPEX for repurposed pipelines

5.2.3 Levelized Cost of Hydrogen Transportation to the Shore ($LCOH_{system}$)

The levelized cost of transporting the hydrogen to the shore ($LCOH_{system}$) via the NGT pipeline, which is one of the main objectives of this research, is presented in this section of the report. As analysed in the previous chapter, the $LCOH_{system}$ includes both the compression cost and the pipeline transportation cost. The costs of electricity production from the offshore wind turbines, the cost of hydrogen production from the electrolyzers, as well as the cost of the substructure for the compressors are not included in this calculation, as it is out of the scope of this study. Therefore, the presented levelized cost refers only to the transportation aspect.

Table 5.19: $LCOH_{system}$ for a newly developed hydrogen pipeline

New Pipeline		
$LCOH_{comp}$	0.141	€/kgH_2/1000 km
$LCOH_{pipe - New}$	0.111	€/kgH_2/1000 km
$LCOH_{system}$ (New)	**0.252**	**€/kgH_2/1000 km**

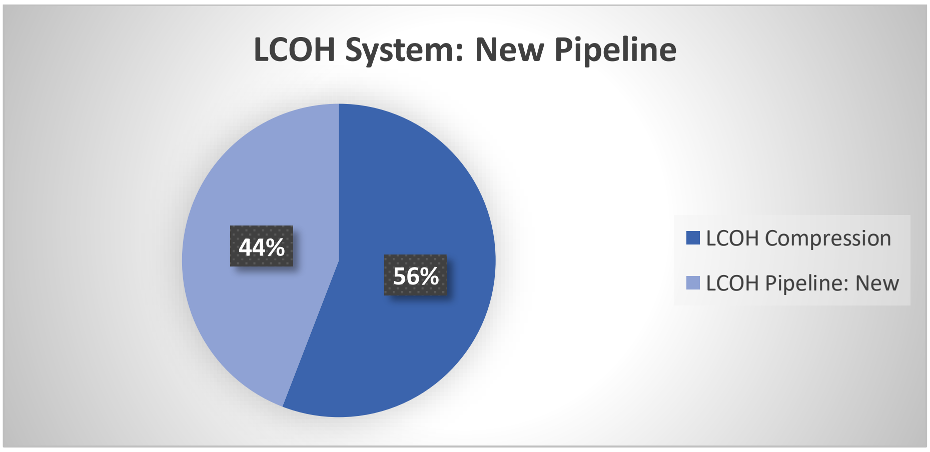

Figure 5.10: $LCOH_{system}$ distribution between the $LCOH_{comp}$ and the $LCOH_{pipe - New}$ for a new hydrogen pipeline

Table 5.20: $LCOH_{system}$ for a repurposed pipeline

Repurposed Pipeline		
$LCOH_{comp}$	0.141	€/kgH_2/1000 km
$LCOH_{pipe - Rep}$	0.026	€/kgH_2/1000 km
$LCOH_{system}$ (Repurposed)	**0.167**	**€/kgH_2/1000 km**

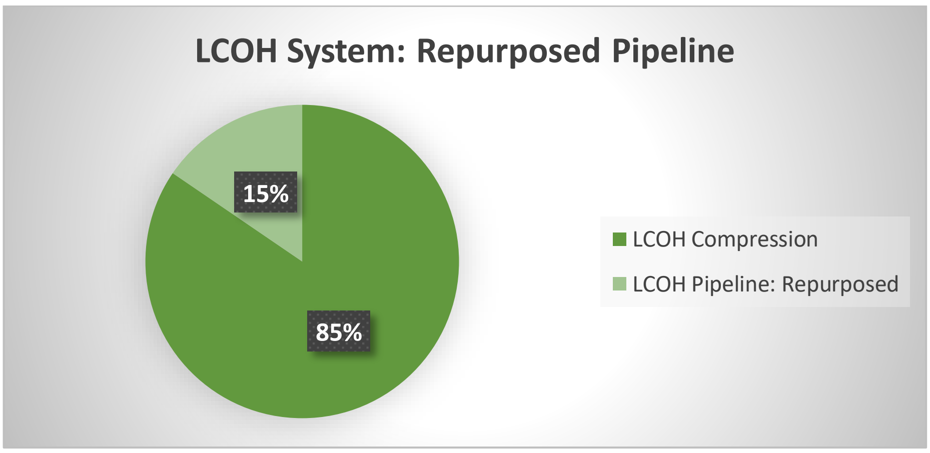

Figure 5.11: $LCOH_{system}$ distribution between the $LCOH_{comp}$ and the $LCOH_{pipe - Rep}$ for a repurposed pipeline

Tables 5.19 and 5.20 present an overview of the overall $LCOH_{system}$, for a new hydrogen pipeline and a repurposed one respectively. Furthermore, the charts of Figures 5.10 and 5.11 illustrate the distribution of the $LCOH_{system}$ for those two cases between the $LCOH_{comp}$ and the $LCOH_{pipe}$. As can be seen, the pipeline costs constitute a much larger percentage of the overall cost in the case of a newly developed pipeline compared to the repurposed pipeline case. In both cases the largest percentage of the overall costs is attributed to the compression costs.

The stacked bar chart of Figure 5.12 presents a detailed cost breakdown for a newly developed pipeline and a repurposed pipeline.

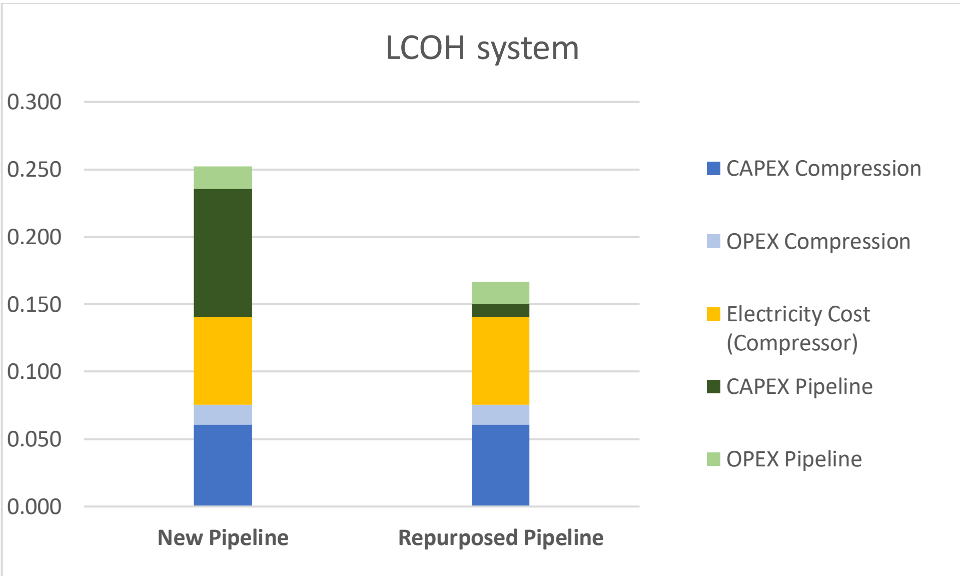

Figure 5.12: $LCOH_{system}$ breakdown for a newly developed and a repurposed pipeline. The presented values are expressed in €/kgH_2/1000 km

5.3 Sensitivity Analysis

To calculate the $LCOH_{system}$ for a repurposed pipeline, a number of assumptions were used in this study, mainly for the economic analysis of the system, which could be a source of potential uncertainty. In this section of the report a sensitivity analysis will be made for the $LCOH_{system}$, to provide information on how sensitive the results are to these uncertainties and determine the main cost drivers. In Section 5.3.1, the sensitivity parameters examined will be described, and in Section 5.3.2, the results of the analysis will be presented, while reflecting on the uncertainty around the assumptions used in this study.

5.3.1 Sensitivity Parameters

<u>Compressor CAPEX ($CAPEX_{comp}$) :</u>

As mentioned in Section 4.2.1, there is uncertainty around the $CAPEX_{comp}$, as various sources include different values for the compressor's capital cost. For this study, the assumption made by van Schot

& Jepma, (2020) of 2 M€/MW is followed, as explained in Section 4.2.1. According to the European Hydrogen Backbone, (2022), the assumed $CAPEX_{comp}$ is about 2.2 M€/MW (corroborating the assumption followed: minor difference), whereas Guidehouse & Berenschot, (2021) assume 3.4 M€/MW in a less optimistic scenario. TNO et al., (2022) also assume a capital cost of 3 M€/MW in their feasibility study for Hy3. Therefore, although the uncertainty is relatively high, based on the range in $CAPEX_{comp}$ of the different sources examined, a sensitivity range of 1.5 - 3.5 M€/MW is assumed in this study.

Compressor OPEX ($OPEX_{comp}$) :

Regarding the operating expenses of the compressor, they are expressed as a percentage of the $CAPEX_{comp}$ in this study. Specifically, as discussed in Section 4.2.1, an assumption made by the the European Hydrogen Backbone, (2022) was followed, namely that the $OPEX_{comp}$ are equal to 1.7% of the $CAPEX_{comp}$. However, literature also mentions higher values for the $OPEX_{comp}$, such as 2% or 3% of the $CAPEX_{comp}$, according to van Schot & Jepma, (2020) and the Council of European Energy Regulators & SUMICSID, (2019) respectively. Therefore, a sensitivity analysis is performed to determine how this uncertainty influences the resulting $LCOH_{system}$, using a 1 - 3% of $CAPEX_{comp}$ range. It should be noted that these percentages only include the compressor's fixed O&M costs and not the electricity costs, which are calculated separately.

New Pipeline CAPEX ($CAPEX_{pipe-New}$) :

As explained in Section 4.2.2, the calculation of the capital expenses of a newly developed pipeline is based on assumptions made by Spyroudi et al., (2020) and van Schot & Jepma, (2020). Specifically, Spyroudi et al., (2020) assume $CAPEX_{pipe-New}$ range of 44 – 50 k€/inch/km and van Schot & Jepma, (2020) assume 40 – 57 k€/inch/km for offshore pipelines. For the calculations performed in this study, the value of 45 k€/inch/km is used. This selection was made because the value is included in both ranges, and at the same time is on the lower side of the range, due to the properties of the North Sea (flat seabed and relatively shallow waters). Nevertheless, a sensitivity analysis is done to examine the extended range of assumed values (40 – 57 k€/inch/km) and investigate how this affects the end result ($LCOH_{system}$).

Repurposed Pipeline CAPEX ($CAPEX_{pipe-Rep}$) :

As was analyzed in Section 4.2.2, the capital expenses of a repurposed pipeline are expressed as a percentage of the capital expenses of a newly built pipeline. In this study it is assumed that the $CAPEX_{pipe-Rep}$ are equal to 10% of the $CAPEX_{pipe-New}$, based on assumptions made by the European Hydrogen Backbone, (2022). This percentage includes the main activities required for a natural gas pipeline to be repurposed for hydrogen transport (e.g., cleaning the pipeline, performing inspections etc.) as has been analysed in more detail in Sections 3.4.1 and 4.2.2. Some literature sources assume a range of 10-35% for the $CAPEX_{pipe-Rep}$, whereas the NGT pipeline operators state that this percentage could be even lower than 10% for the NGT pipeline, since there are no especially costly activities involved in the repurposing process. Taking these into consideration, the sensitivity range examined for the $CAPEX_{pipe-Rep}$ is between 5% and 35% of the $CAPEX_{pipe-New}$.

<u>Pipeline OPEX ($OPEX_{pipe}$) :</u>

Concerning the operating expenses of the pipeline, they are expressed as a percentage of the $CAPEX_{pipe-New}$. More specifically, the assumption followed in this study is derived from the European Hydrogen Backbone, (2022), where a range between 0.8 and 1.0% of the $CAPEX_{pipe-New}$ is used. As analysed in Section 4.2.2, in this study the $OPEX_{pipe}$ are assumed to be 1% of the $CAPEX_{pipe-New}$. However, other literature sources state that the $OPEX_{pipe}$ could be higher than 1% of the $CAPEX_{pipe-New}$, which would affect the $LCOH_{pipe}$ as well as the end result. Specifically, Spyroudi et al., (2020) estimate that the $OPEX_{pipe}$ are equal to 3% of the $CAPEX_{pipe-New}$, and the Council of European Energy Regulators & SUMICSID, (2019) estimate 2%. Since the uncertainty around the costs of repurposing natural gas pipelines into hydrogen is still high, a sensitivity analysis is performed to determine how the $OPEX_{pipe}$ assumption affects the end result, using a sensitivity range of 0.8-3.0% of $CAPEX_{pipe-New}$.

<u>Electricity Cost :</u>

As mentioned earlier, the electricity is not included in the $OPEX_{comp}$ calculations, as it is calculated separately. It is dependent on the amount of electricity used in MWh and the cost of electricity in MWh. Van Schot & Jepma, (2020) state that electricity produced by offshore wind in the North Sea will cost around 30 – 40 €/MWh, according to the Dutch government's projections, whereas the European Hydrogen Backbone, (2022) use a range of 40 – 80 €/MWh to also explore a 'high-cost' scenario. On the other hand, other sources state that at renewable resources sites with high potential, the electricity cost would be in the order of 10 – 20 €/MWh around 2030 (van Wijk, 2021a). Given that the studied site for offshore hydrogen production has very high potential, being located in the North Sea, the final electricity production cost is on the low side. The cost range assumed for investigating the sensitivity of the $LCOH_{system}$ to the electricity cost parameter is 10 – 60 €/MWh.

<u>WACC :</u>

The final parameter investigated in this sensitivity analysis is the discount rate or weighted average cost of capital (WACC). In this study, the WACC value used for the economic calculations is 5%, based on the assumption made by the European Hydrogen Backbone, (2022) and TNO et al., (2022). Even though an interest rate of 5% is commonly used in many sources in literature, several publications choose different values. For example, Guidehouse & Berenschot, (2021) chose a discount rate of 4% for the offshore infrastructure, van Wijk & Wouters, (2021) use 7%, and van Schot & Jepma, (2020) assume 10%. The interest rate value depends mainly on the maturity of the technology, which is dictated by important technological developments, and whether revenues are regulated. In case such developments take place in the offshore infrastructure sector, including wind turbines, hydrogen production, and compression technologies, the discount rate value could be further reduced. However, the WACC projections could potentially be very optimistic regarding some parts of the analysed system. Even though an entirely accurate interest rate value cannot be projected, since the studied case is planned for the future, a range of 3% - 10% is used in this analysis, to investigate different scenarios and the level of influence over the end result ($LCOH_{system}$).

5.3.2 Sensitivity Results

All the sensitivity parameters analyzed are summarized in Table 5.21. Specifically, the table includes the selected values, the value range chosen for an optimistic scenario (max) and a pessimistic scenario (min), as well as the resulting overall cost ($LCOH_{system}$) for both scenarios.

The methodology followed in this analysis is individually adjusting key parameters and assumptions used in this study (i.e., sensitivity parameters), based on a pessimistic and an optimistic scenario, to evaluate the effect these have on the $LCOH_{system}$. The sensitivity analysis results are also presented in the graph of Figure 5.13.

Table 5.21: Sensitivity parameters analysed for minimum and maximum values and the resulting $LCOH_{system}$

Sensitivity Parameter	Min. Value	Selected Value	Max. Value	Unit	$LCOH_{system}$ Min. (€/kg/1000km)	$LCOH_{system}$ Max. (€/kg/1000km)
$CAPEX_{comp}$	1.5	2.0	3.5	M€/MW	0.15	0.22
$OPEX_{comp}$	1.0	1.7	3.0	% of $CAPEX_{comp}$	0.16	0.18
$CAPEX_{pipe - New}$	40	45	57	k€/inch/km	0.16	0.17
$CAPEX_{pipe - Rep}$	5	10	35	% of $CAPEX_{pipe - New}$	0.16	0.19
$OPEX_{pipe}$	0.8	1	3	% of $CAPEX_{pipe - New}$	0.16	0.20
Electricity Cost	10	40	60	€/MWh	0.12	0.20
WACC	3	5	10	%	0.15	0.21

As can be seen observed, the uncertainty around the compressor capital cost ($CAPEX_{comp}$) could potentially have the largest effect on the end result. A 75% increase of the $CAPEX_{comp}$ value (3.5 M€/MW) results in a 34% $LCOH_{system}$ increase (0.22 €/kg/1000km), whereas a 25% reduction (1.5 M€/MW) reduces the $LCOH_{system}$ by 11% (0.15 €/kg/1000km). The electricity cost parameter also has significant contribution to the resulting $LCOH_{system}$, since 75% decrease results in a 29% decrease of the $LCOH_{system}$, according to the optimistic scenario, whereas a 50% electricity cost increase would cause a 20% $LCOH_{system}$ increase, according to the pessimistic scenario. The sensitivity results regarding the $CAPEX_{comp}$ and electricity costs confirm one of the main conclusions of this study, that the $LCOH_{system}$ is primarily affected by the compression costs (mainly $CAPEX_{comp}$ and electricity costs), and not so influenced by the costs of repurposing the NGT pipeline. Another parameter which has significant contribution to the end result is the WACC. Specifically, in the pessimistic scenario there is a 24% $LCOH_{system}$ increase, whereas in the optimistic case there is an 8% decrease.

Another conclusion drawn by the sensitivity analysis regarding the repurposed pipeline cost is that the uncertainty around the $OPEX_{pipe}$ could affect the end result more than the $CAPEX_{pipe}$. Specifically, according to the pessimistic scenario for the $OPEX_{pipe}$, the $LCOH_{system}$ shows a 20% increase according to the pessimistic scenario, whereas the $CAPEX_{pipe}$ have a significantly lower influence over the $LCOH_{system}$. In fact, the uncertainty around $CAPEX_{pipe - Rep}$, $CAPEX_{pipe - New}$, and $OPEX_{comp}$ affects the $LCOH_{system}$ the least.

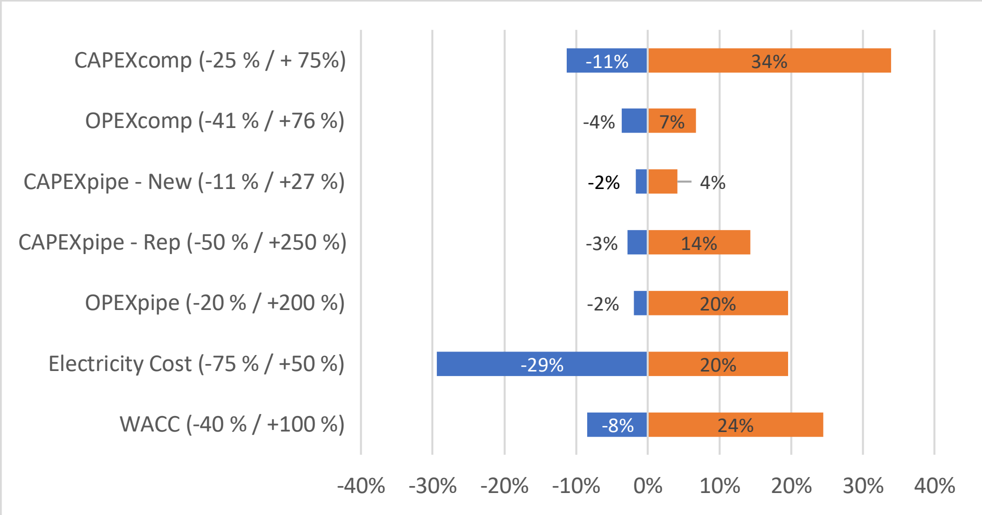

Figure 5.13: Results of the sensitivity analysis, including different values of the examined parameters and the level of impact of each on the $LCOH_{system}$

Since the number of sensitivity parameters examined is high, a simplified approach is followed, according to which each sensitivity parameter is changed individually, while the others are set at their predetermined value (initial assumption). In reality, the parameters could be combined in various ways, resulting in numerous different scenarios. Nevertheless, the sensitivity analysis performed is sufficient for this study since it provides useful information regarding the main cost drivers and the level each assumption affects the $LCOH_{system}$. It should be also noted that several sensitivity parameters are examined for particularly high/low values, in order to evaluate the system's response even to extreme deviations from the initial assumptions.

The main conclusions drawn by the sensitivity analysis are that the $LCOH_{system}$ for a repurposed pipeline is primarily affected by the compression costs, and particularly by the capital expenses and electricity cost, and that the $OPEX_{pipe}$ have a greater influence over the $LCOH_{system}$ than the $CAPEX_{pipe – Rep}$. The uncertainty is generally high, since the studied technology is new, and the economic analysis is done with a top-down approach. To obtain more accurate results with less uncertainty, a more detailed bottom-up economic analysis should be performed.

6

Discussion

The main focus of this research study was on proposing and analysing a system configuration for transporting green hydrogen produced by offshore wind turbines to the shore via repurposed pipeline (NGT). Two of the key components of the hydrogen transportation system were analysed in more detail, namely the hydrogen compressor unit and the actual pipeline, from a technical and an economic point of view. In this part of the report, the research results and the assumptions and data used will be discussed and evaluated, regarding both the technical and economic aspects of hydrogen transportation via offshore pipelines. Specifically, comparisons will be drawn between this study and other commercial projects and pieces of scientific research also examining offshore hydrogen production, compression, and transportation to the shore via pipelines.

First of all, it is worth noting that the assumptions made in this research reflect the current knowledge and projections of future technology advancements. Consequently, in the future (and specifically around 2030 according to the projected timeline of this study) various assumed values might fluctuate notably, based on increased technological maturity and/or other geopolitical developments. Some examples could include the CAPEX and OPEX of the electrolyzer, the compressor, and the pipeline, but also the efficiency of the electrolyser and the compressor, the system's dynamic behaviour due to fluctuating wind, and the connections between main pipeline and wind farms at different parts of the pipeline. Moreover, it should be pointed out that via optimization (e.g., on the wind turbines - electrolyzer configuration, or the compressor placement and integration) further cost reduction could be potentially achieved, although optimization has not been an aspect of this research.

Pressure drop

The flow behaviour of hydrogen inside the pipeline described in this study is confirmed by Abbas et al., (2021) and Witkowski et al., (2017), stating that along the length of a pipeline, the pressure losses as well as the temperature changes, decrease the density of hydrogen and at the same time increase its flow velocity, resulting in a further rise of the pressure drop. Specifically, regarding the pressure drop of hydrogen flowing in the NGT pipeline, as analysed in this study, it was found to be 10.4 bar along the 253.2 km of the pipeline's length, for the average (operation) flow case. This value is in accordance with González Díez et al., (2020), who state that the anticipated pressure drop level for a normal North Sea pipeline ranges from 3 to 10 bar per 100 km, for similar conditions.

Energy & Mass transport capacity

According to the graph of Figure 6.1, which depicts how the hydrogen transport capacity and the energy transport capacity change based on the pipeline diameter and operating pressure (González Díez et al., 2020), several comparisons with the present study can be made. Specifically, for a 36-inch pipeline (representing the diameter of the NGT pipeline) and a pressure of 65 bar (representing the average pressure along the NGT pipeline for the maximum flow scenario), the energy transport capacity is approximately 230 PJ/y and the mass transport capacity approximately 1,600 kton/y. These values are very similar and comparable with the corresponding calculated values in this study, which are 246 PJ/y and 1,734 kton/y respectively.

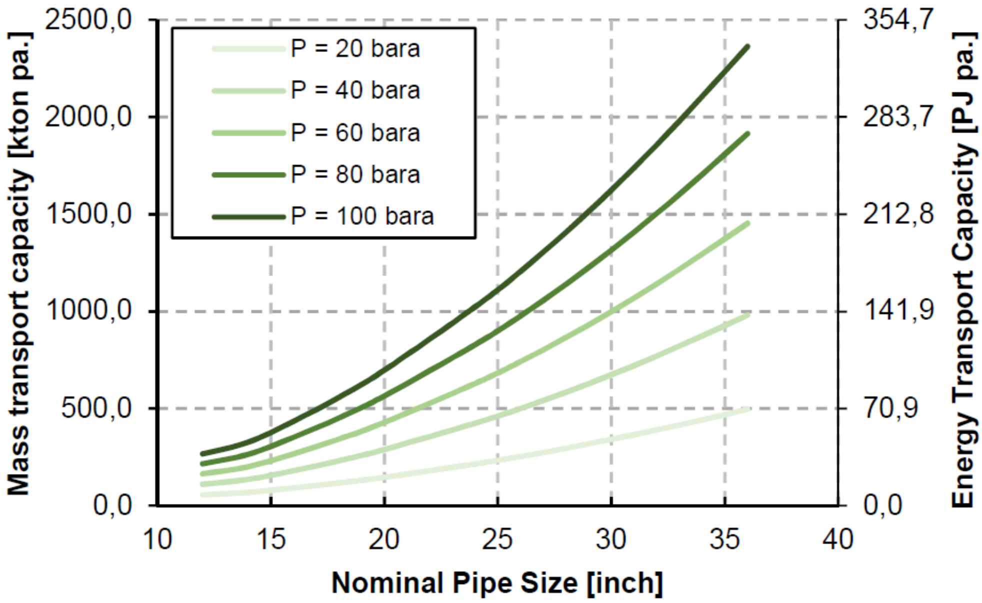

Figure 6.1: Energy and Mass transport capacity for a hydrogen pipeline based on the operating pressure and pipeline diameter (González Díez et al., 2020)

More specifically, concerning the mass transport capacity of the NGT pipeline, its potential hydrogen mass flow rate is 220 tonH_2/h (based on 80 bar and 15 m/s conditions) (González Díez et al., 2020). The corresponding value for the maximum flow rate scenario analysed in this study, based on similar conditions, is calculated at 198 tonH_2/h. This indicates that the NGT pipeline is capable of accommodating the maximum possible hydrogen flow (all 10 GW of offshore wind from search areas 7 and 3 converted into hydrogen). As explained in the previous chapter, the maximum needed pipeline capacity is calculated by multiplying the 10 GW of offshore wind with the electrolyzer efficiency on HHV (78.8%). This indicates that the maximum capacity needed is approximately 7.9 GW.

Volumetric flow

Hydrogen's volumetric flow rate inside the pipeline, generally needs to be approximately triple that of natural gas, considering hydrogen's energy content is three times lower than natural gas, in order to transport the same amount of energy over the same time (Abbas et al., 2021). Even though currently there are still no similar projects of such large scale, there are some ongoing smaller scale or pilot projects, studying the offshore green hydrogen production, powered by offshore wind in the North Sea such as the PosHYdon and H2opZee projects. However, these projects – and especially PosHYdon are of a much smaller scale and therefore can't be compared with the present case study since they are not representative. Nevertheless, the volumetric flow of hydrogen through the NGT pipeline was verified by NGT in an interview (R. Hagen, M. Ros, personal communication, October 11, 2022).

Flow velocity

Concerning the hydrogen's flow inside the NGT pipeline, taking into account the average (operating) flow scenario, the hydrogen velocity does not exceed 12.2 m/s when reaching the shore, whereas for the maximum flow scenario, hydrogen's velocity does not exceed 23 m/s. According to González Díez et al., (2020), the assumed hydrogen flow velocity in existing repurposed pipelines in the North Sea is 15 m/s, taking into account similar operating conditions, which is near to the calculated values for the present study. This velocity value could be further raised in case parameters like pipeline erosion limit, vibrations caused by the flow, and associated equipment (e.g., flow meters) allow it (González Díez et al., 2020). Moreover, Miralda van Schot and Catrinus Jepma, (2020) in their analysis use flow velocities between 10-20 m/s for hydrogen pipeline transportation, placing the calculated velocities (for both average flow and max flow scenarios) of the present study very close to the acceptable range. Finally, the resulting velocities were also verified by NGT during an interview(R. Hagen, M. Ros, personal communication, October 11, 2022).

Economic considerations

Beginning with the compressor economics, the calculated $CAPEX_{comp}$ value in the present study was calculated according to André et al., (2014) and van Schot & Jepma, (2020) assumption of 2,000 €/kW, resulting in approximately 205 M€. This value is verified by González Díez et al., (2020) research, according to which the CAPEX of compression are approximated at 25,000 €/$MW_{H2\text{-}input}$. Specifically, based on the electrolyzer efficiency (78.8% - HHV) and the 10 GW of total assumed electrolyzer capacity, the electrolyzer's hydrogen output amounts to 7.9 GW (according to the maximum scenario). Therefore, the $CAPEX_{comp}$ calculation normalized to the current values would result in 197 M€, which is comparable to the original calculation. The $OPEX_{comp}$, excluding electricity costs, were calculated as a percentage of the $CAPEX_{comp}$ (1.7%), resulting in approximately 3.5 M€/y (European Hydrogen Backbone, 2022). Earlier studies (Council of European Energy Regulators & SUMICSID, 2019; van Schot & Jepma, 2020) assume similar values for the $OPEX_{comp}$ (3% and 2% of the corresponding $CAPEX_{comp}$ respectively), resulting in comparable results. Regarding the electricity costs for powering the compressor's electric motor, those were calculated according to M. A. Khan et al., (2021), resulting in around 62 k€/y/km.

Concerning the pipeline cost analysis, as explained in the previous chapters, this was done for a newly developed, as well as for a repurposed pipeline. The repurposed pipeline CAPEX were calculated as a fraction (10%) of the new pipeline CAPEX, according to European Hydrogen Backbone, (2022). This is verified by ACER, (2021), who estimate a range of 10-35% for the repurposed pipeline CAPEX, but also by NGT during an interview (R. Hagen, M. Ros, personal communication, October 11, 2022). In fact, NGT believe that this percentage could be even lower, since there are no particularly costly activities involved in repurposing. The CAPEX of a new pipeline were calculated assuming 45 k€/inch/km, based on the pipeline length (253.2 km) and diameter size (36''), resulting in approximately 410 M€ (van Schot & Jepma, 2020). Similar result would also be obtained if the Spyroudi et al., (2020) $CAPEX_{pipe}$ range was used for the calculation (44-50 k€/inch/km). The $OPEX_{pipe}$ (assumed same for both new and repurposed pipelines) were calculated as a percentage of the CAPEX of a new pipeline (1%), according to European Hydrogen Backbone, (2022), resulting in around 4.1 M€/y.

Apart from the cost of transporting hydrogen via pipeline (including the repurposing and compression costs), there is also an extra cost of making a tie-in from the compressors to the main pipeline. Although such connections are traditionally built by welding, the tie-in could also be achieved by utilizing mechanical hot tap tee clamps, which is a new technology. According to the NGT and NOGAT pipeline operators, replacing welded connections with mechanical hot tee clamps could reduce the tie-in cost significantly, since underwater welding is a very labour-intensive activity. Specifically, apart from the welding procedure, which requires specialised divers, a dome around the connection point also needs to be built. On the other hand, mechanical hot tee clamps have a more straightforward operating principle, analysed in more detail in Section 2.5, allowing for simpler and safer pipeline connections, which could drastically reduce the tie-in cost.

It is also important to note that apart from the direct cost advantage of repurposing existing pipelines over developing new ones in the North Sea, there are also other factors that make repurposing preferable to building new pipelines for transporting hydrogen to the shore. Some examples that could indirectly affect the cost include reduced realization time, considerably lower environmental impact, as well as straightforward connection to the shore, due to the already existing connection.

<u>LCOH</u>

Overall, the results of the analysis indicated that repurposing the NGT pipeline for the transportation of green hydrogen produced offshore is feasible and economically favourable. As far as the $LCOH_{comp}$ distribution is concerned, the largest part of the overall cost is attributed to the electricity cost for powering the compressor motor (47%), followed by the CAPEX of the compressor (43%), whereas the remaining 10% is represented by the fixed OPEX. Regarding the $LCOH_{pipe}$ there is a dramatic distribution difference between the CAPEX and the OPEX of a new and a repurposed pipeline. Specifically, the pipeline CAPEX correspond to 85% of the overall cost in the case of a newly developed pipeline, whereas in the case of a repurposed pipeline, the largest percentage corresponds to the OPEX (63%). Moreover, the overall $LCOH_{system}$ distribution between the $LCOH_{comp}$ and $LCOH_{pipe}$ shows a significant difference for new and repurposed pipelines. In fact, for a new pipeline the $LCOH_{system}$ is relatively evenly distributed between the $LCOH_{comp}$ and the $LCOH_{pipe}$ (56% - 44%), whereas for a repurposed pipeline, the greatest portion of the costs is attributed to the $LCOH_{comp}$ (85%). Finally, the total costs calculated for both new and repurposed pipelines are in accordance with the values of the European Hydrogen Backbone, (2022). Specifically, for a new pipeline, the $LCOH_{system}$ was found to be

0.25 €/kg/1000 km, which falls within the EHB range for similar conditions and input parameters (0.19-0.32 €/kg/1000 km). The same applies to the $LCOH_{system}$ for a repurposed pipeline, which was calculated at 0.17 €/kg/1000 km (corresponding EHB range: 0.07-0.17 €/kg/1000 km). The calculated $LCOH_{system}$ values are also consistent with Leonhard et al., (2021), who give a range of 0.07-0.23 €/kg/1000 km (based on HHV_{H_2}) for 100% hydrogen pipeline transport.

Sensitivity & Model Validation

Given that the economic analysis was done top-down, which includes making several assumptions based mainly on literature, a sensitivity analysis was also done, in order to reflect on the uncertainty around the assumptions used in this study. After assessing a number of different sensitivity parameters, the main conclusion drawn by the sensitivity analysis is that the uncertainty around the costs of compression (i.e., CAPEX and electricity costs) leads to the largest uncertainty in the $LCOH_{system}$.

Regarding the validation of the model, the main issue is that there are no similar cases of large-scale offshore hydrogen production and transport via repurposed pipelines implemented in practice. Therefore, it is not possible to validate the model by comparing it to figures from industry. However, the comparison of the model results with the European Hydrogen Backbone, (2022) and Leonhard et al., (2021), in combination with the sensitivity analysis and the validation by NGT and NOGAT during an interview (R. Hagen, M. Ros, personal communication, October 11, 2022), indicate that the results are robust for the uncertainties examined.

Project Timeline

According to information provided by NGT and NOGAT during an interview, rerouting natural gas from the NGT to the NOGAT pipeline system, and therefore making NGT available for 100% hydrogen transportation, could be achieved by 2027 (R. Hagen, M. Ros, personal communication, October 11, 2022). However, the main obstacle would be the speed at which the political decisions are made, for instance regarding the appointing of the offshore wind search areas in the North Sea for dedicated offshore hydrogen production. Such decisions need to be accelerated, in order to achieve the target, set by REPowerEU for renewable hydrogen production in the EU by 2030. Concerning the depletion date of the natural gas fields in the North Sea, most fields are expected to stop producing between 2026 and 2030, according to input provided by NGT and NOGAT. Overall, the proposed timeline for this project is between 2027 and 2030. Even though according to existing policies, hydrogen is planned to be produced offshore after 2030, the political decision process needs to be accelerated, in order to enable faster offshore hydrogen production in the North Sea and meet the targets set by REPowerEU by 2030.

7

Conclusion & Recommendations

7.1 Conclusion

The aim of this research study was to examine the geographical, technical, and economic feasibility of large-scale green hydrogen transportation (produced offshore with green energy from wind turbines), with parallel natural gas transport, utilizing new and already existing gas infrastructure in the North Sea, by 2030. To begin with, an elaborate analysis on the geographical and physical configuration of the system was made, exploring different scenarios for the parallel hydrogen and natural gas transportation via existing North Sea pipelines. After concluding on the optimal scenario, the main focus was placed on the hydrogen transportation part of this system, and its techno-economic implications. A technical analysis of the main components of the transportation system was made, namely the hydrogen compressor and repurposed pipeline, inspecting various technical aspects, like the required compression capacity and hydrogen flow characteristics among others. Finally, an economic evaluation of the project's feasibility was performed, leading to the overall LCOH estimation for the analysed system.

The research sub-questions set in the introduction of this thesis report will be individually addressed below, resulting in answering the main research question of this study.

- **How will such a system physically look? What would be a possible configuration of offshore hydrogen production in the North Sea, when utilizing existing and new infrastructure?**

Regarding the geographical configuration of the proposed system, two different scenarios for the parallel transportation of natural gas and hydrogen to the Dutch shore via existing and new pipelines were proposed and thoroughly examined. The final scenario selection was made based on a detailed analysis of the offshore wind search areas in the Dutch continental shelf, their future potential, and the possible energy transportation methods associated with them, among other considerations. The selected scenario includes the utilization of the offshore wind search areas 7 and 3 (total of 10 GW) for hydrogen production, repurposing the NGT pipeline for 100% pure hydrogen transportation, and rerouting the natural gas to the NOGAT pipeline. The physical configuration of the proposed system will be comprised of the following components: Offshore wind turbines located at search areas 7 & 3 incorporating in-turbine electrolysis for green hydrogen production (decentralized), infield pipelines of relatively small diameter to transport the produced hydrogen to the compression stations, compressors to boost the hydrogen, and the repurposed NGT pipeline (36’’) to facilitate its transportation to the shore. The proposed geographical layout can be seen in the maps of Figures 2.9 and 2.11.

- **What are the technical characteristics of hydrogen transportation via pipeline in the North Sea?**

In order to investigate the technical characteristics of hydrogen transportation, an elaborate analysis of the proposed system’s components, from the energy production by the offshore wind turbines to the transportation of the produced green hydrogen through the NGT pipeline, was made. The key components of the transportation system, and, therefore main elements of the technical analysis, are the compressor and the actual pipeline. Regarding the compression characteristics, the total rated compressor power, required for handling the entire 10 GW of offshore wind converted into hydrogen, was found to be 103 MW. Regarding the hydrogen flow through the NGT pipeline, a hydraulics analysis was made, evaluating parameters like the pressure drop, density, temperature, velocity, and friction factor, among others, verifying that transporting hydrogen to the shore via the NGT pipeline is feasible from a technical standpoint. Specifically, for an average flow scenario, the pressure drop over the (usable) length of the NGT pipeline (253.2 km), was found to be 10 bar. Therefore, with an initial pressure of 65 bar the hydrogen would reach the shore at around 55 bar, which is an acceptable value for the onshore hydrogen backbone (according to Gasunie: no less than 50 bar). Table 7.1 presents the most important technical parameters for the average (operating) flow and maximum flow scenarios.

Table 7.1: Key technical parameters for the average (operating) flow, and maximum flow scenarios

Parameter	Average (Operating) Flow Scenario	Maximum Flow Scenario	Unit
Pipeline Diameter	36	36	inch
Pipeline Length	253.2	253.2	km
Pipeline Capacity	4.5	7.9	GW
Hydrogen Flow	114	199	ton/h
Flow Velocity	12	23	m/s
Input Pressure	65	80	bar
Pressure at the Shore	55	51	bar
Pressure Drop	10	29	bar

- **What is the levelized cost of the hydrogen (LCOH) transport?**

To calculate the levelized cost of hydrogen (LCOH) transport, a detailed economic analysis was made regarding the key components of the proposed system (compressor and pipeline). It should be noted that cost analysis of the offshore wind turbines, electrolysis components, and substructures for compressors was not included, as it was out of the scope of this study. The overall LCOH for the proposed system, including hydrogen compression and NGT pipeline repurposing costs, was found to be 0.17 €/kg/1000 km. This value is acceptable according to literature, as explained in the previous chapter, indicating that the proposed system for hydrogen transportation to the shore is economically feasible. The main cost driver of the presented LCOH transport for a repurposed pipeline was found to be the compression costs. In Figure 5.12 a detailed breakdown of the LCOH transport can be found.

Main research question:

- **How could the offshore infrastructure system in the North Sea be reused for green hydrogen transportation, with parallel natural gas transportation?**

The main conclusion of this study is that reusing existing offshore infrastructure for the transportation of green hydrogen (produced offshore) in the North Sea is feasible from a geographical, technical, and economic point of view, and could be achieved at the competitive price of 0.17 €/kg/1000km. This value is in accordance with literature for repurposed pipelines of similar diameter. Another key finding of this research is that the main cost driver for repurposed pipeline systems is hydrogen compression, contrary to newly constructed pipeline systems, according to which compression and pipeline development costs are evenly distributed. The research results indicate that it is economically feasible to transport energy via molecules (hydrogen) over long distances, especially when utilizing existing infrastructure which further reduces the overall cost. This is also in line with literature, stating that when energy production and conversion occurs far from the shore (distances greater than 140km), reusing existing offshore infrastructure is usually the factored choice for cost-effective transportation (van Schot & Jepma, 2020).

7.2 Recommendations for Future Research

This section will discuss several suggestions to further investigate and analyse the transportation of hydrogen produced offshore via existing repurposed pipelines. It should be noted that at the time of writing this report, the present research was among the very few accessible studies regarding the green hydrogen transportation via repurposed offshore pipelines, and the first study to analyse such a system form a geographical, technical, and economic standpoint. Consequently, it is apparent that for several sections of this study a broader level of detail was employed, since the objective was to provide an overview of the entire hydrogen offshore transportation system, rather than investigating each aspect of it in detail. Several suggestions that could possibly inspire future research projects are presented below:

- Examining hydrogen storage possibilities, to deal with the fluctuations of the hydrogen flow, since its production comes from an intermittent energy supply (offshore wind turbines), in order to have baseload at the demand site. In this study the average and maximum hydrogen flow was modelled, although to obtain more detailed results and better optimize the system, options such as salt caverns located nearby in the North Sea, utilizing the pipeline’s volume, or even electrical storage possibilities could be evaluated.

- Applying the methodology used in this research to other case studies, examining alternative geographical layouts and topologies or energy production methods. For instance, evaluating the applicability of the current results in different offshore settings with not as flat and shallow seabed as the North Sea (mainly for new offshore infrastructure development). Furthermore, instead of offshore wind turbines powering up the electrolysis unit, different energy production methods could be explored (e.g., offshore solar PV).

- Addressing various limitations of the present study. One of the limitations is that a top-down assessment of the pipeline and the compressor costs (CAPEX and OPEX) is done, instead of a bottom-up analysis. Doing a bottom-up analysis would be an important piece of follow-up work, which would result in more accurate and detailed results, without having to make a large number of assumptions. More specifically, regarding the cost analysis, future research could include the cost of compression platforms, cost of infield pipelines, the LCOH of hydrogen production, as well as the offshore wind LCOE, to make a more thorough overall cost evaluation. As far as the technical considerations are concerned, a more detailed analysis of the substructure of the compressor, as well as on how the electrification of the compressor would work could be made. Moreover, the operational behavior of the compressor and the pipeline could be further investigated, in terms of safety and long-term reliability of the assets.

- Setting a detailed timeline for the development of the project. This research estimates that the project could be deployed around 2030, however a more elaborate analysis could be made, taking into account the respective policies and other considerations (e.g., ecological studies etc.) needed to be in place for this to be accomplished.

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Appendix

Infield Pipelines Modelling

To determine the physical configuration of the infield pipelines, and therefore the layout of each wind farm (search area 7 & 3), 30 different scenarios were modelled, exploring different number of wind turbines connected to each infield pipeline (ranging from 5 to 30), and different infield pipeline diameters (8'', 12'', 20'', 36'', and 48''). For simplicity, it is assumed that both search areas 7 and 3 have a squared grid layout. Based on the proposed rotor diameter of each wind turbine (222 m), it is also assumed that the distance between two neighboring turbines is six to eight times the rotor diameter (Energypedia, 2015), resulting in a 1.75 km × 1.75 km grid. The distance between the final wind turbine and the compression station is assumed to be 3 × 1.75 km = 5.25 km. Finally, for the needs of this analysis it is assumed that each compressor station is placed in a separate location (and not all of them in a single platform) as can be seen in the sketches of Figures 3.13 and 3.14. As already mentioned in Section 5.1, based on the compressor modelling, the total number of compressors required was found to be 7: 5 compressors for S.A.7 and 2 compressors for S.A.3. A different configuration for the compressor's arrangement could also be explored, by placing more than one compressor on each platform. For that to be achieved, a more in-depth analysis should be made, to evaluate the spatial footprint and weight of hydrogen reciprocating compressors of such scale, as well as the vibrations caused by them (due to their piston-based operation), and whether that would pose an issue for the offshore platform and its substructure.

The sensitivity analysis was made on the basis of how many wind turbines could be connected to a single infield pipeline without a significant pressure drop being created along the pipeline. An increased pressure drop along the infield pipelines would lead to a lower suction pressure for the compressor, which would suggest that additional compression would be required for hydrogen to travel through the NGT pipeline. That would, in turn, imply higher compression costs since both the $CAPEX_{comp}$ (increased compression capacity needed) and the electricity requirements (to power the compressor motor) would be higher.

Therefore, the core of this sensitivity analysis is the trade-off between the number of wind turbines that could be connected to each infield pipeline (more pipelines lead to higher pipeline costs, due to increased overall length) and the pressure drop (leading to higher compression costs).

The main results of the sensitivity analysis for the infield pipelines can be seen in Table A.1. The results regarding larger diameter pipelines (20'', 36'', 48'') are not included in the table, since the respective costs would be significantly higher than the lower diameter pipes, even though the resulting pressure drops were negligible. The pressure drop values were calculated using the same model as the main part of the study, based on the Darcy-Weisbach equation and the total length was derived from the assumptions regarding the distance between two wind turbines.

Table A.1: Sensitivity analysis results for the infield pipelines modelling, considering different number of wind turbines connected per pipeline and different pipeline diameters

Scenarios	# Wind Turbines	Pressure Drop (bar)	Total Length (km)
A: Diameter 8''			
A1	5	0.14	12.25
A2	10	1.26	21.00
A3	15	3.88	29.75
A4	20	9.52	38.50
A5	25	29.00	47.25
B: Diameter 12''			
B1	5	0.02	12.25
B2	10	0.13	21.00
B3	12	0.20	24.50
B4	15	0.40	29.75
B5	20	0.88	38.50
B6	22	1.23	42.00
B7	25	1.70	47.25
B8	30	3.12	56.00

As can be derived from the results of Table A.1, for smaller pipeline diameter (8'') the pressure drop increases dramatically. Therefore, the infield pipelines diameter is assumed to be 12'', since larger diameter pipes would be much costlier. Given that 12'' pipelines could still be quite expensive, additional types (e.g., flexible pipelines) should also be examined instead of steel pipes, to reduce the overall cost (Bai & Bai, 2014). Keeping in mind the squared layout assumption for both wind search areas, as well as the approximate number of wind turbines attributed to each one of them (based on each search area's potential capacity and the assumed nominal capacity of a single wind turbine – 15 MW), scenario B3 was selected for search area 3 and B6 for search area 7. Specifically, for search area 3: a total of 12 infield pipelines with 12 wind turbines per pipeline, and for search area 7: a total of 24 infield pipelines with 22 wind turbines is assumed. The proposed layouts of the wind farms, including infield pipelines and compression station locations for search areas 7 and 3, are depicted in the sketches of Figures 3.13 and 3.14 respectively. More details for each wind farm are summarized in Table A.2. The maximum capacity is found for a single string and is calculated as the product of the number of wind turbines connected to a single pipeline, the nominal capacity of a single wind turbine, and the electrolyzer efficiency in terms of HHV.

It should be noted that this sensitivity analysis has more of a superficial nature, since it was not in the direct scope of this research study, as the cost differences between different pipeline sizes are not accounted for in detail and many assumptions were made. In a full integrated optimization, the increased pressure drop leading to higher compression costs should be weighed against the precise cost differences in pipelines, although for that to be accomplished, sufficient data would be required.

Table A.2 : Search area 3 & 7 layout and infield pipelines characteristics

Parameter	Search Area 3	Search Area 7	Unit
# WTGs per pipeline	12	22	-
# Pipelines	12	24	-
# WTGs total	144	528	-
Pipeline Diameter	12	12	inch
Pipeline Length	24.5	42	km
Mass Flow	0.56	1.06	kg / s
Electrolyzer Outlet Pressure	30	30	bar
Compressor Inlet Pressure	29.8	28.77	bar
Pressure Drop (ΔP)	0.2	1.23	bar
Capacity (HHV)	142	260	MW
# Compressors	2	5	-
Rated Power per compressor	10.25	16.41	MW