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Marinized Hydrogen in the North Sea Region

FINAL REPORT

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ABBREVIATIONS AND DEFINITIONS

ABP	Associated British Ports
AC	Alternative Current
AE	Alkaline Electrolyser
CAPEX	Capital Expenditure
CFD	Computational Fluid Dynamics
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CTV	Crew Transfer Vessel
DAC	Direct Air Capture
DC	Direct Current
GH_2	Gaseous Hydrogen
Green Hydrogen	Hydrogen produced from renewable energy
H_2	Hydrogen
HISC	Hydrogen Induced Stress Cracking
ICE	Internal Combustion Engine
IGF Code	International Code of Safety for Ships Using Gases or Other Low-Flashpoint Fuels
IMO	International Maritime Organization
ISO	International Standards Organization
LH_2	Liquefied Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LOLER	Lifting Operations and Lifting Equipment Regulations
NG	Natural Gas
NO_X	Nitrogen Oxides
NSR	North Sea Region
O&G	Oil and Gas
O&M	Operations & Maintenance
OPEX	Operational Expenditure
OSV	Offshore Service Vessel, a generic term for vessels operating in the offshore industries
PEM	Proton Exchange Membrane
PLC	Programmable Logic Controller
PM	Particulate Matter
PTP	Point-to-Point
R&D	Research & Development
RFID	Radio Frequency Identification

Ro-Pax	Roll-on/roll-off freight and passenger vessel
Ro-Ro	Roll-on/roll-off freight vessel
SCR	Selective Catalytic Reduction
SIL	Safety Integrity Level
SMR	Steam Methane Reforming
SOE	Solid Oxide Electrolyser
SOFC	Solid Oxide Fuel Cell
SOV	Service and Operations Vessel
SO_X	Sulphur Oxides
TEU	Twenty-foot Equivalent Unit
TRL	Technology Readiness Level (EU definition)

BE	Belgium
DE	Germany
DK	Denmark
FR	France
NL	Netherlands
NO	Norway
SE	Sweden
UK	United Kingdom

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1.0 INTRODUCTION AND OBJECTIVES

The potential development of hydrogen power trains in shipping and the resulting requirement for hydrogen bunkering is a major part of the potential hydrogen economy in the North Sea Region (NSR). This report reviews the current state of hydrogen technology for propulsion and auxiliary power in shipping, both on board a vessel and onshore, as well as general transportation, storage and safety requirements. The onboard technology review covers onboard storage and propulsion while the onshore review covers production, transportation and offloading (or bunkering). Onshore offloading systems are considered from a fixed facility to a floating vessel, either onshore or offshore (such as from a platform or bunkering vessel). Safety considerations are explored for both liquid (LH_2) and gaseous (GH_2) hydrogen fuel in comparison with natural gas (NG) and liquified natural gas (LNG).

2.0 FUEL ANALYSIS

This section to identifies fuels that can be used for powering watercraft without emitting pollutants during operation. Production methods that use renewable/carbon-free electricity, as opposed to fossil-derived production methods are considered. These fuels are renewable ammonia, renewable hydrogen, synthetic methane and synthetic methanol (e-methanol). Data was collected through a literature review and interviews.

2.1 Fuel Assessment Criteria

Fuel candidates were evaluated based on the list of fuel selection criteria below. Fuels that did not meet at least one of the criteria were not considered.

- **A: Can the fuel be consumed at its point of use without emitting pollutants?**
  In the context of this project, the fuels considered were those that have zero emissions from 'well-to-wake': from production of the fuel through to propulsion or auxiliary power on board. Furthermore, so-called net-zero fuels, for which chemicals for production are extracted from the environment and released in the production process as pollutants, also did not meet this criterion.
- **B: Does technology exist today to consume the fuel for maritime and terrestrial applications?**
  Fuels for which such technology is not commercially available or has a TRL level of less than 7 are not considered as candidates, bearing in mind that such technologies should be mature by 2030. This was applied to all supply stages, i.e., production, storage, transport, bunkering and on-board use.
- **C: Can the fuel be produced from upstream renewable/carbon-free electricity?**
  Only fuels that can be produced by using such electricity sources for the production process are considered for this project. This includes electricity from offshore wind farms or carbon-free grid electricity.

- **D: Does the fuel need any feedstock that is not locally available?**
  The upstream emissions for transport and production of any fuel constituents were considered. If constituents like nitrogen or biomass would need to be sourced from abroad in the necessary quantities, this criterion was not met.
- **E: Can the fuel be used for planned non-maritime applications?**
  As the project seeks to find other potential uses, candidates were evaluated for non-maritime uses that are relevant to the Grimsby area.
- **F: Does the fuel present any particular hazards (safety and environmental) for production, storage and use?**
  Fuels that can be produced, stored or used in a harbour environment or adjacent geographical context, met this criterion.
- **G: Do regulations, standards and guidelines for the production, storage, transport and use for the fuel in maritime applications exist?**
  The development of regulation specific to maritime use was considered for the selection.
- **H: Is the fuel candidate being currently considered/or under consideration for building supply chains in other ports?**
  Fuels for which this is the case were favoured over others, as the existence of supply chains is likely to build a stronger use case in general.
- **I: What is the comparative cost among fuel candidates?**
  The price of electricity will dominate all fuels produced from electricity, so this is a primary uncertainty. The cost of these alternative fuels is much higher than for fossil fuels because supply chains are still being built. Costs can be expected to reduce as systems develop. Hydrogen has so far had significant development activity and current activities identified in the ports analysis (Section 4) indicate that this will continue to be the case in the immediate future. This means its cost will likely come down more quickly than the other alternative fuels.

Table 1 summarises the criteria for assessing fuels.

Criterion		Ammonia from renewables	Hydrogen	Synthetic methane from renewables	Synthetic methanol from renewables
A	No emissions at point of use?	yes, if used as hydrogen carrier with fuel cells	yes, in fuel cells	no	no
B	Does technology exist?	no	LH_2 bunkering not mature	yes	yes
C	Can be produced with electricity?	yes	yes	yes	yes
D	Is feedstock locally available?	yes	yes	yes	yes
E	Non-maritime use?	Chemical industry Fertilizer	Chemical industry Domestic cooking Rail vehicles fuel Residential heating Road vehicles fuel	Chemical industry Domestic cooking Residential heating Road vehicles fuel	Chemical industry
F	Is it hazardous?	yes	yes	yes	yes
G	Is it regulated?	in development	in development	yes	yes
H	Do supply chains exist elsewhere?	yes	yes	in development	in development
I	Is it available in Humber ports?	no	planned	no	no
J	What is the cost? (avg.	260	260	> 210	650

	USD/MW·h at shaft)				

Table 1 – Overview of fuel selection criteria

2.2 Discussion of Fuels

- **Criterion A: No emissions at point of use?**
  Emissions in this context are greenhouse gases (carbon dioxide and methane), nitrogen oxides (NO_X), sulphur oxides (SO_X) and particulate matter (PM). The combustion of ammonia or hydrogen in an internal combustion engine (ICE) is not emission-free. The creation of NO_X is inherent to engines and needs to be mitigated. In marine engines, selective catalytic reduction (SCR) is typically used which can significantly reduce the NO_X levels, but not eliminate them completely (Wärtsilä, year unknown). In addition, where a pilot fuel is used to ignite the fuel in the combustion chamber, emissions from its combustion occur. Therefore, the use of ICEs cannot be considered free of emissions, irrespectively of the fuel used.
  The direct use of ammonia in fuel cells is possible, although NO_X emissions occur depending on the type of fuel cell used (Jeerh et al, 2020). No direct ammonia fuel cells for maritime use are commercially available. If ammonia is used as hydrogen carrier and cracked beforehand, its hydrogen can be used in emission-free marine Proton Exchange Membrane (PEM) fuel cells that are commercially available. However, the cracking process is energy intense and small-scale cracking is not commercially available (Power Engineering, 2021).
  Carbon emissions occur when synthetic natural gas or methanol are used in fuel cells or ICEs.

- **Criterion B: Does technology exist?**
  Renewable production exists or is under development (Rolls-Royce Holdings Plc, 2021; Maritime Executive, 2022) for all fuel candidates albeit at different scales. Specifically, to ship technology, only a few ship projects are underway to investigate ammonia or methanol use for powering ships. More than 60 hydrogen ship projects exist worldwide (ZEM Tech, 2021; MacLaine et al., 2021). Ammonia does not meet the TRL of 7, while hydrogen and methanol technologies are developing through R&D activity in the maritime industry. Hydrogen still needs to mature liquefied bunkering and bulk transport, whereas there are not enough methanol ship projects yet to be considered mature[1].

- **Criterion C: Can be produced with electricity?**
  All fuel candidates meet this criterion.

- **Criterion D: Is feedstock locally available?**
  Hydrogen can be produced wherever water and electricity are available. The carbon and nitrogen

[1] Note that AP Møller Maersk announced in August 2021 that they will build 8 large container vessels to be fuelled by e-Methanol or Bio-methanol. However, this is an application for deep sea ships rather than short sea ships.

necessary to produce ammonia, methanol and methane are present in the air, although it is often found in literature that e.g., biomatter is preferred as a source of carbon as opposed to extraction from the atmosphere, because direct air capture (DAC) is more energy intensive. DAC is also less developed than biomatter technologies.

- **Criterion E: Non-maritime use?**
  The addition of hydrogen to the existing natural gas network is included in the UK's hydrogen strategy with the objective to reduce emissions of residential use (UK Government, 2021a). This is not possible with ammonia or methanol, whereas synthetic methane is technically equivalent to natural gas.

- **Criterion F: Is it hazardous?**
  All fuel candidates are flammable and each has its own individual hazards and safety issues. Hydrogen is the only candidate where regulations specific to maritime and land vehicles use are under development, see also criterion G.

- **Criterion G: Is it regulated?**
  Production, storage and transport is covered by regulations on land for all fuel candidates. Methane and methanol are covered by the International Maritime Organization (IMO) International Code of Safety for Ships using Gases or other Low-flashpoint Fuels (IGF Code). Hydrogen regulation is under development at national levels, however no international regulation exists yet. Some Classification Societies have developed rules for hydrogen use on ships and more recently also for ammonia (AEA, 2021). According to industry contacts, the maritime use of ammonia for four stroke engines lags behind LNG engines. Ammonia is seen as an important possibility for 2 stroke engines. The main market for alternative fuels for Grimsby is for short sea shipping, where 4 stroke engines are dominant.

- **Criterion H: Do supply chains exist elsewhere?**
  Development of green hydrogen is widespread in the NSR (see Figure 15 “Map of green hydrogen production in North Sea Region ports”). Various hydrogen strategies were published by European governments in recent years. Supply chains for fossil-derived ammonia, methane and methanol exist. There are 11 projects for development of synthetic methanol in Europe (Methanol Institute, 2021). Production of renewable ammonia and synthetic methane are also under development (Methanol Institute, 2021; Cames et al., 2021).

- **Criterion I: Is it available in Humber ports?**
  Hydrogen is not yet available, but renewable hydrogen production is planned in Immingham. No production facilities for the other candidates were identified in the Humber area. See Figure 15 "Map of green hydrogen production in North Sea Region ports".

- **Criterion J: What is the cost?**
  All alternative fuel candidates require electricity and therefore the cost of electricity is a dominant component of the overall price of the fuel and the primary uncertainty. Currently the cost is much

higher than for fossil fuels because supply chains are in their infancy. As the systems are developed, hydrogen costs can be expected to reduce more rapidly for hydrogen as it is the fuel being developed the most. Renewable ammonia and renewable hydrogen are expected to have similar cost at around 260 USD per delivered MWh when used in fuel cells. The price of synthetic methane is estimated to be at least three times that of (fossil) LNG and is slightly lower than the former two at approx. 210 USD/MWh (DNV GL, 2019). It is to be noted that these figures are sourced from various literature and there is considerable variation. The production cost of synthetic methanol is estimated to lie between 800-2400 USD/t, which, assuming a Lower Heating Value (LHV) of 5.47 MWh/t and a total conversion efficiency of 45% translates to 325-975 USD per delivered MWh (IRENA, 2021). The Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping finds that the e-methanol price 20% above e-hydrogen and e-ammonia and the e-methane price is equal to e-methanol price. While these estimates have large ranges, it appears that e-methanol and e-methane are more expensive than e-hydrogen and e-ammonia

3.0 INFRASTRUCTURE TECHNOLOGY REVIEW

3.1 Green Hydrogen Production

3.1.1 Alkaline Electrolysers

Commercial Alkaline Electrolysers (AE) have been available for over a century at scales of hundreds of MW, as shown in the image below.

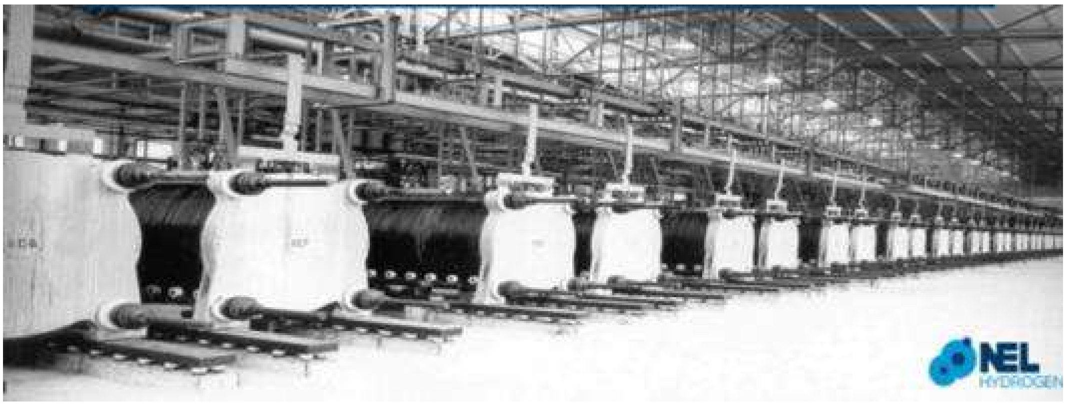

Figure 1 – A 135-MW alkaline electrolyser facility in Norway, operational from 1953 (NEL Hydrogen)

Alkaline technology is reliable, well understood and available in two forms: the simpler (and lower cost) atmospheric pressure version and more sophisticated pressurised systems, which operate at about 15 bar pressure. Both operate at low temperatures (around 70°C) and have poor efficiency curves, forcing the operators to run them gently to improve the efficiency to an acceptable level.

3.1.2 Proton Exchange Membrane Electrolysers

PEM electrolysers are also low-temperature systems and were developed in the 1960s but were only used at significant scales in the last decade by the military. Currently, commercial systems have increased in scale from a few kW to over 10 MW.

Interest in PEM electrolysers has risen because of:

- They have better efficiency curves than AE, allowing them to operate at up to 10 times higher at current densities and therefore have a smaller area footprint;
- They allow better separation of gases, leading to lower water purity being required and better efficiency;
- They report higher response rates to time varying currents, making them more suited to connection to renewable sources

However, PEM electrolysers have some disadvantages compared to AE electrolysers:

- They require the use of platinum, iridium and ruthenium catalysis, significantly affecting the cost/kW;

- Constructing large PEM electrolyser stacks is difficult, meaning that the large electrolysers that are being planned for the next decade require many dozens, or possibly hundreds of stacks, leading to high cost and complexity;
- PEM electrolyser lifetimes are uncertain.

3..1.3 Solid Oxide Electrolysers

Solid Oxide Electrolysers (SOE) operate at high temperatures (500°C or higher), taking advantage of the thermodynamics leading to the splitting of water being more efficient. This step change in efficiency has motivated considerable research in recent years, and the technology is now starting to become commercial.

However, this technology also has the following negative aspects:

- To survive the high temperatures, rare and expensive materials are required;
- The various materials in each cell have slightly different coefficients of thermal expansion, which leads to delamination of layers after repeated heating and cooling cycles. Thus, they operate best with a continuous output.

3.2 Transportation

For pure hydrogen to be seen as a future fuel to drive decarbonisation and become a mainstream fuel, it will require reliable methods for transportation.

Reliable, sustainable, and cost-effective transportation of hydrogen is a prerequisite to the competitiveness and uptake of hydrogen. With the centralisation of production offshore, there is a greater likelihood that offshore green hydrogen can dominate supply to short sea shipping.

As well as the potential for fuelling maritime vessels, offloading systems also create a wider opportunity for marine hydrogen trade, providing ports with the opportunity to diversify their energy requirements using low carbon fuels as well as providing new revenue streams for the sale and distribution of green hydrogen.

Similar to LNG, hydrogen can be liquefied before being loaded onto highly-insulated tankers. Boil-off of product would still remain as a key concern, even when utilizing bunkers with active cooling measures. On an eleven-day journey (typical of a bunker trip from Australia to Japan), a LH_2 carrier vessel could experience losses of 2% of cargo, though a portion could be utilized for ship propulsion (similar to LNG bunkers).

Hydrogen as a fuel is non-metallic, non-toxic and has a higher energy density of mass than any other fuel source. Unfortunately, its energy density by volume is lower than other fuels.

For land-based hydrogen mobility applications, hydrogen is usually stored in the vehicle at pressures of 700 bar for cars, and 350 bar for buses, trains and other large vehicles. There are multiple reasons for this, but include the following:

- Cars have limited storage volume, and therefore higher pressures must be used, while buses and trains can accept higher storage volumes;
- Larger vehicles consume more fuel and therefore need a larger mass of hydrogen to be stored, therefore lower priced 350 bar storage is more acceptable;
- The adiabatic compression of the hydrogen in the pressure vessels results in a significant release of heat during refuelling. If uncontrolled, this heat could lead to failure of the storage. As such, compression to 700 bar requires pre-cooling the hydrogen to -40°C, careful control of flow rates, temperature monitoring of the pressure vessels and infra-red communication with the refuelling system. This all adds complexity and cost.

Below is an example of a typical hydrogen vehicle refuelling system produced by ***tpgroup***.

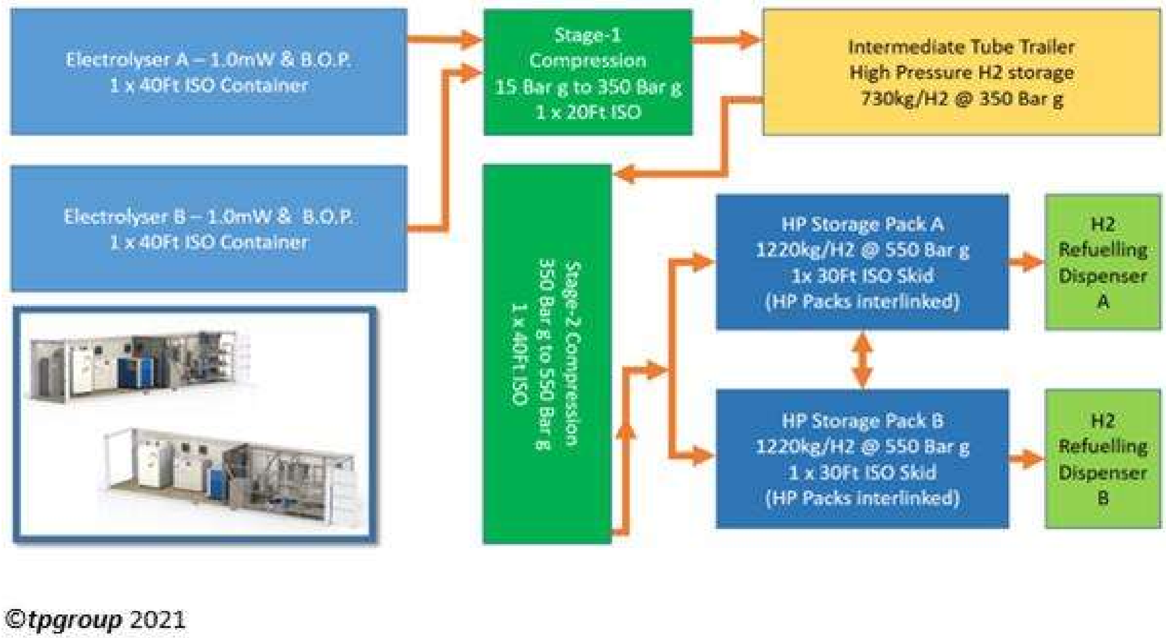

Figure 2 – Hydrogen vehicle refuelling system (tpgroup, 2021)

At present, there is no standard hydrogen storage pressure for maritime applications; as such this document makes reference to both 350 and 700 bar storage.

Even if pressurised to 700 bar, the energy density of hydrogen is 1,250 Wh/L (at LHV), compared to diesel at 10,720 Wh/L and petrol at 9,500 Wh/L. However, achieving these pressures with hydrogen is not simple. As a diatomic gas, hydrogen has a compressibility factor of <1, meaning that the density at high pressure is less than would be expected from the pressure. If hydrogen can be liquefied (at -252°C at atmospheric pressure), the energy density increases to 2,360 Wh/L (LHV) which, while substantially less than traditional fuels, is still a significant improvement.

3.3 Offloading Systems

For marine offshore applications, the transmission and offloading of LNG is currently the closest comparative process to hydrogen offloading. This section will therefore compare and contrast typical LNG offloading systems to currently available hydrogen offloading technology to identify practical use cases that incorporate lessons learned.

When considering current technology which is used in heavy industry as feedstock in the chemical industry, it is essential to have a clear understanding of hydrogen in all its forms. How we transport, offload or bunker hydrogen will be dependent on the form of hydrogen being transported. Section 6 discusses the advantages and disadvantages of both gaseous and liquid hydrogen. Here, it is considered what effect these have on the practical aspects of bunkering.

Hydrogen is either stored as a gas or liquid and can be transferred through a pipe/hose or delivered in a container. Therefore, the following systems have been considered, which are discussed in detail:

- Gaseous Hydrogen Systems
- Liquid Hydrogen Systems
- Containerised Hydrogen Systems (being either gaseous or liquid)

3.3.1 Gaseous Hydrogen Bunkering

For this analysis, the hydrogen is generated at low pressure (20 to 30 bar is typical) in an electrolyser and eventually transferred to the ship via a flexible hose. There are two key methods that can be used to transfer the gas, as explained here.

Cascade filling

The first method is cascade filling, wherein the hydrogen storage is filled to a higher pressure than the target pressure for the ship's tanks (typical numbers would be 350 bar[2] target pressure in the ship and 500 bar storage on the platform). The storage is divided into multiple banks of pressure vessels. Each bank is then opened in turn to the ship's depleted storage and the gas is transferred as the pressure between the ship and the platform equalises. After the first bank is opened, the pressure in both the ship and the platform storage vessels may be ~250 bar. On opening the second bank, the pressure will level at 300 bar, the third at 325 bar and finally, the fourth bank will level at the desired 350 bar.

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[2] As discussed previously, 350 bar is a typical pressure for land-based transport applications.

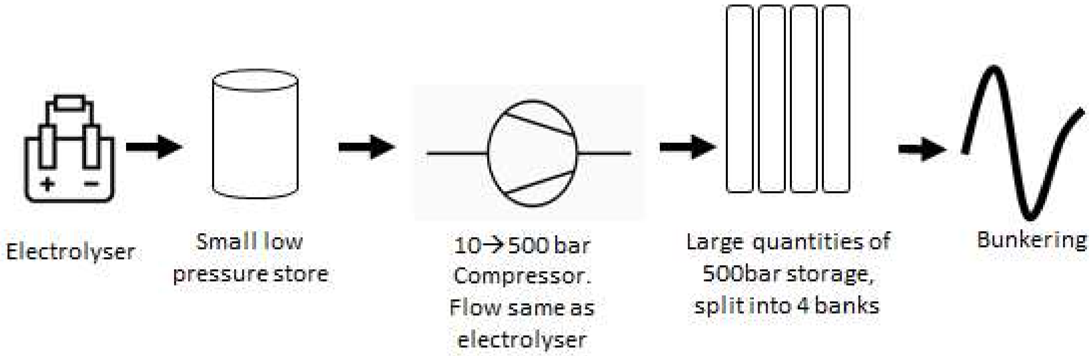

Figure 3 – Diagram of the equipment required for cascade filling

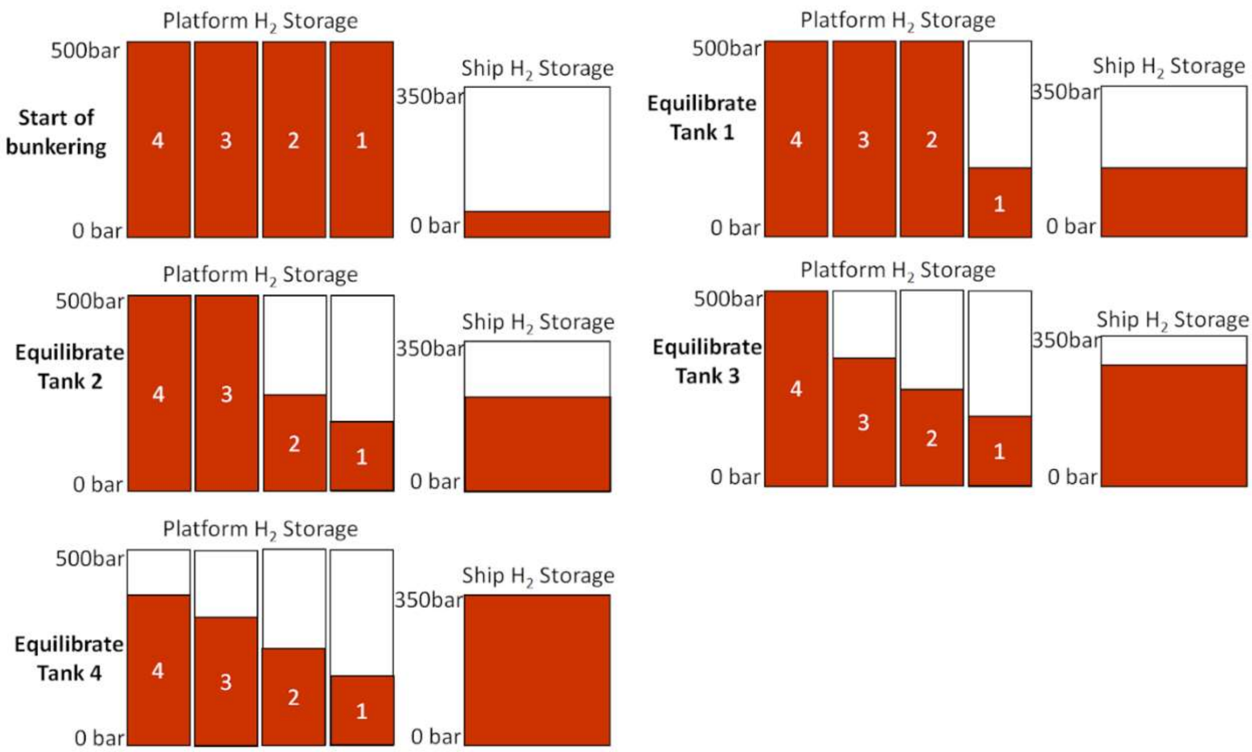

Figure 4 – Diagram explaining cascade filling

The advantages of this system are that:

- By splitting into banks and opening each in turn, the volume of hydrogen that is required to be stored is reduced, improving safety and reducing cost;
- A single compressor is required which operates between the electrolyser output pressure (at about 20 bar) and 500 bar, but with a low flow rate equivalent to the electrolyser flow rate, which is relatively inexpensive;
- Relatively high pressures and short bunkering times can be achieved. The only limitation is the diameter of the hoses and the desire to prevent overheating of the hydrogen storage on the ship due to the adiabatic compression of the hydrogen within it. If this were left uncontrolled, it could lead to

catastrophic failure of the ship's hydrogen storage. If modelling showed the transfer rates were too high, a restrictor could be placed in the line to limit the flow.

However, the key disadvantages of this bunkering method are:

- Despite cascade filling reducing the storage requirement, it still requires a large amount of relatively expensive high pressure storage;
- Despite the efficiency of the cascade filling process, much of the storage cannot be depleted and as such inaccessible to the ship[3]. While the exact numbers will depend on the design of the system and the ship, typically, if 1 kg of H_2 is required to fill the vessel, about 1.4 kg of 500 bar storage is required.

Direct filling

In this method hydrogen is compressed directly from low pressure tanks on the platform into the ship. The advantage of this solution is that no high-pressure storage is required, reducing the cost and complexity of the system.

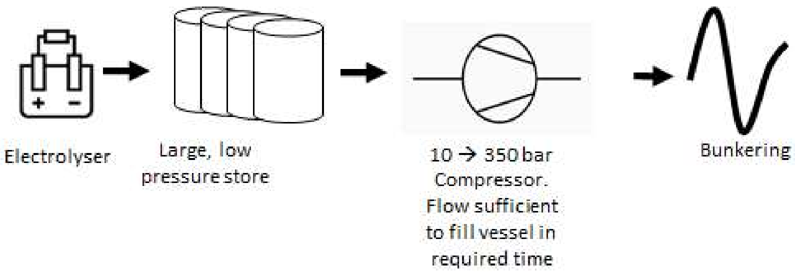

Figure 5 – Diagram of the equipment for direct filling

However, there are disadvantages of direct filling:

- In the simplest iteration, the 'low pressure tanks' are at the output pressure of the electrolyser. However, being at such a low pressure, these will take up a very large volume compared to the 500 bar storage discussed for cascade filling. So, if 1 kg of H_2 per day is required for refuelling, 2 kg of 20 bar storage is required if the electrolyser operates at 20 bar and the compressor minimum input is 10 bar. This, ignoring the compressibility factor, will require 30 times the storage volume. This is likely to be too high if space is a limiting factor. One possible solution for platforms with limited space could be subsurface storage. Below the surface, the pressure increases by 1 bar for every 10m depth; thus, at 100m, the pressure is 10 bar, equivalent to the compressor input. If the storage could be made either using a flexible or piston design, then irrespective of how full the storage was, it would always have a minimum pressure of 10 bar and all of the storage would be accessible to the compressor. However, the upthrust from the storage would be significant and require considerable anchoring on the seabed.

[3] In the above example, the first bank of vessels equilibrated in pressure at 250 bar. Thus, all of the remaining hydrogen in that bank was unused, and indeed inaccessible to the ship.

- This will require a compressor capable of accepting 10 bar input hydrogen and an output of gas at 350 bar, but with a flow rate designed to transfer all of the hydrogen to the ship as quickly as possible to minimise the bunkering time. Thus, direct filling requires a flow rate often 5 to 10 times faster than the compressor used for cascade filling, which can lead to a very high CAPEX.

Hybrid Filling Systems

To overcome some of the disadvantages of the cascade and direct filling systems, it is possible to have hybrid filling systems. For example, it is possible to use cascade filling for the bulk of the hydrogen transfer, then top up with direct filling. Here, smaller cascade banks are used, so that they equilibrate below the desired level and when the cascade is complete, a compressor is used to directly fill the ship from the cascade banks for perhaps the last 100 bar, with a flow rate substantially lower than the pure direct fill.

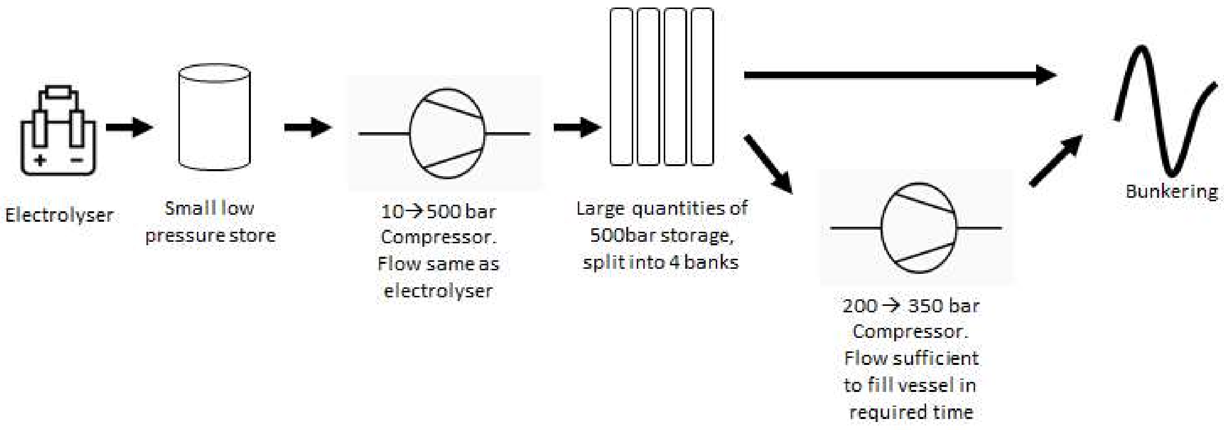

Figure 6 – Diagram of an optional hybrid filling layout

While this requires two compressors (a 10 to 500 bar slow throughput compressor to fill the cascade and a 200 to 500 bar high throughput booster compressor to complete the direct fill), the second compressor is a relatively low cost model. In addition, less storage is used than direct filling and more of it is accessible.

Furthermore, to reduce the footprint of 20 bar storage required for direct filling, it is possible to use intermediate storage of 200 bar. Although this requires a second compressor, 200 bar storage is lower cost per kg of storage and has a substantially lower footprint.

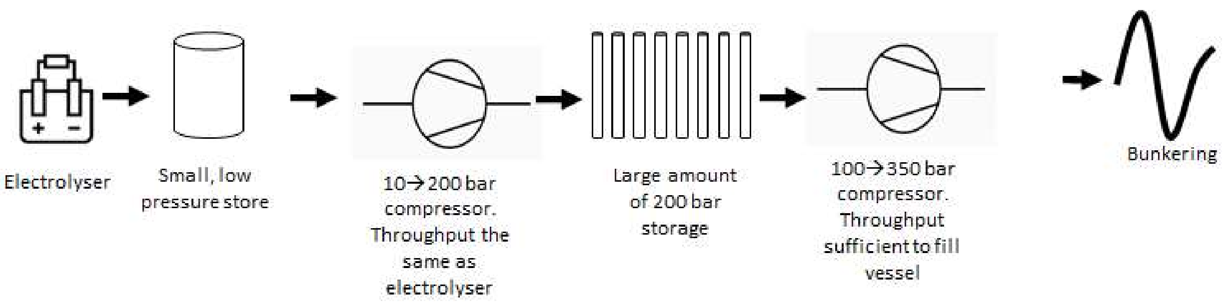

Figure 7 – Diagram of an alternative optional hybrid filling layout

3.3.2 Liquid H_2 Bunkering

Once hydrogen is generated as a low-pressure gas, it is then liquefied (through cooling to -253°C at atmospheric pressure; a process which can take consume 12 kWh/kg H_2[4], or up to 36% of the energy entrained in the hydrogen), hydrogen will be stored in vacuum insulated cryogenic tanks on the platform until ready for transferring to the ship. These tanks are designed to minimise the boil off gas such that <0.12% is lost per day, in line with IMO requirements for LNG[5], with the boil off fed back into the system and re-liquefied LH_2 has a volumetric energy density of 8,500 MJ/m^3 compared to approximately 40,000 MJ/m^3 for HFO or 17,855 MJ/m^3 for methanol.

The liquid hydrogen could be dispensed directly to the ship that requires refuelling or to a dedicated bunker vessel, which could then be used to refuel the final vessel. For the mechanics of offloading, for LH_2 there is no distinction between final vessel and the bunker vessel[6].

Once connected, the transfer will be undertaken via a vacuum insulated hose, complete with interlocks to ensure safe connection. However, it should be noted that double metal-walled hoses are not particularly flexible. Thus, the traditional method of pulling the hose to the vessel via a pilot line suspended from a boom over the ship, is likely to be impractical. However, if it is arranged, the hose will require a breakaway coupling, which will snap and seal both ends if the ship and bunkering facility move too far apart.

Discussions have been undertaken with two suppliers, Man-Cryo and Cryostar, to ascertain their approach to LH_2 bunkering. Each has a different approach to the best method to physically transfer the hydrogen through the hose to ship, as described below.

Man-Cryo would install a small evaporator working against ambient air on the quay/platform to produce a controlled amount of gaseous hydrogen. This gas is then used to pressurise the platform's LH_2 tank and push the hydrogen to the ship. A typical set up for a small ship can transfer 4 tonnes LH_2 in about 1 hour, although this speed can clearly be increased by using a wider diameter hose.

Cryostar would use cryogenic pumps to transfer the hydrogen to the ship, with the speed being varied by the capacity of the pump. While this method is simpler in terms of the process engineering, the CAPEX of the cryogenic pump is likely to be significant.

Both systems will require a bunkering panel between the quay/platform's tank and the ship to control the flow of gas. Its functions will include:

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[4] Provided in discussion with Crystar

[5] Boil-Off Gas Formation inside Large Scale Liquefied Natural Gas (LNG) Tank Based on Specific Parameters, Mohamad Shukri Zakaria, Applied Mechanics and Materials 229-231:690-694.

[6] This is notably different to a gaseous system, where if a bunker vessel were to be used with cascade filling, the storage on the bunker vessel would need to be at a higher pressure than on the ship. In turn, the platform would require storage at a higher pressure than on the bunker vessel.

- Purging the line before transfer with an inert gas (to prevent any air in the line forming an explosive mixture);
- Monitoring and controlling the flow of liquefied hydrogen via instructions to the pump / vaporizer unit;
- Monitoring the line pressure, quay/platform tank pressure and level, and ship tank pressure and level to ensure all are within safe limits. Pressure relief valves will be included should the control system fail;
- Shutting down the system once the ship's tank is full (or the quay/platform's tank was empty) or in response to an emergency alarm

Man-Cryo presently locates the bunkering panel on ship, primarily to minimise the port-side equipment (all the ship requires on the port-side is an LH_2 trailer to meet it). However, looking to the future, it is envisaged that this equipment would be mounted on the platform.

The bunkering operations will be overseen by a Programmable Logic Controller (PLC) with a second PLC overseeing all of the safety critical systems. The reliability of both key sensors and the PLC will be determined by Safety Integrity Level (SIL) analysis.

On the ship and platform, all seals are potential leak points, and risk assessments will be required to ensure that the risks of fire and asphyxiation are considered and minimised.

3.3.3 Containerized Hydrogen Systems

"Containerised refuelling" is a term used to describe the process of filling modules of compressed or liquefied hydrogen storage (usually in a 20-foot or 40-foot ISO frame) and then lifting them onto the vessel where they can connect into the ships fuel system. Bunkering therefore consists of lifting the empty storage off the ship and replacing with full storage.

This idea is being developed by many companies, particularly those who manufacture frames of compressed hydrogen storage, and has the following advantages:

- Bunker times are reduced as fuelling takes no more time than loading and securing containers, something the shipping industry is very adept at;
- For gaseous hydrogen, containerised refuelling overcomes the problem of an efficient way of transferring gas from the platform to the vessel. In comparison, both direct and cascade filling result in a considerable amount of storage which is inaccessible to the ship being refuelled;
- For LH_2, it removes the requirement for a cryo-pump or tank that can self-pressurise to transfer the hydrogen to the ship. The LH_2 can simply be generated, stored and physically lifted into position.

However, while appealing, there are the following substantial issues with containerised refuelling:

- Of all of the bunkering methods previously in this report, ownership and responsibility for equipment is clear with regards to who purchases them, who maintains them and who is responsible in the event of a failure. With containerised filling, this is not so clear. Early in the hydrogen rollout, where a single platform is supplying a limited number of ships, ownership could be clearly defined and the storage easily tracked. However, when multiple platforms owned by different operators are bunkering many vessels, the frames of stored hydrogen will be swapped many times between different platforms and ships. The owner will find it difficult to track their equipment, and harder to perform mandatory inspections. However, with modern technology, it would not be impossible. A scenario could exist where the owners of the storage leased the equipment to the ship operators and platforms, who in turn checked them during refuelling using RFID, or similar technology;

- If ships are allowed alongside the platform for refuelling, there are considerable safety implications of using a crane at sea to lift a 40-foot frame filled with LH_2 or pressurised H_2, swing it over the side of the platform and lower it onto the deck of a vessel which is likely to be rolling in the swell. Dropping a container onto the vessel deck (or another container), could result in a catastrophic release of hydrogen;
- If, as seems likely, an exclusion zone would be present around the platform to prevent impacts, this would result in the bunkering point being located at a substantial distance from the platform storing the hydrogen. It is unclear how the fuel containers would be safely moved to the ship. Therefore, this solution is more suited to refuelling in a port rather than a platform;
- The repeated connecting and disconnecting of fittings on the ship or container would lead to wear and potential leakage;
- While swapping containerised hydrogen has been completed commercially on land, this has not been attempted in a marine environment (to the authors' knowledge). As such, a platform operating this method would be considered a pilot plant at TRL 5.

Currently, the standards for off-loading containers is ISO 10855. This document specifies requirements for the design, manufacture and marking of offshore containers with a maximum gross mass not exceeding 25,000 kg, intended for repeated use to, from and between offshore installations and ships. This document specifies only transport-related requirements.

In offshore environments, the lifting of offshore containers shall be performed in compliance with DNVGL-ST-0378, a standard for offshore and platform lifting appliances. All containers should be designed with their own dedicated lifting bridle with certified and rated lifting arrangement. All lifts plans will be conducted under Lifting Operations and Lifting Equipment Regulations (LOLER). On balance, it is recommended that containerised filling only be considered when there is a clear ownership model for the equipment and a safe and practicable method for transferring the containers at a distance from the platform can be identified.

4.0 PORTS ANALYSIS

The Ports Analysis is an exercise to understand Grimsby's regional context in an emerging international maritime hydrogen economy. This undertaking aims to describe overall trends in the sector, specify the strategic opportunities and risks facing Grimsby, and explain how green hydrogen development and potential in Grimsby compares with that of neighbouring ports.

4.1 Introduction

Today, the production, transport and supply of hydrogen is a mature and extensive industry in the NSR. Currently, 457 facilities across the EU, UK and Norway produce 11.5 million tonnes of hydrogen, either directly (merchant or captive) or as a by-product of other manufacturing processes, as shown in Figure 8 (Pawelec et al., 2020). Merchant production is defined as direct, dedicated hydrogen production, while captive is the production of hydrogen for use in a specific purpose on-site or as a by-product of an industrial process.

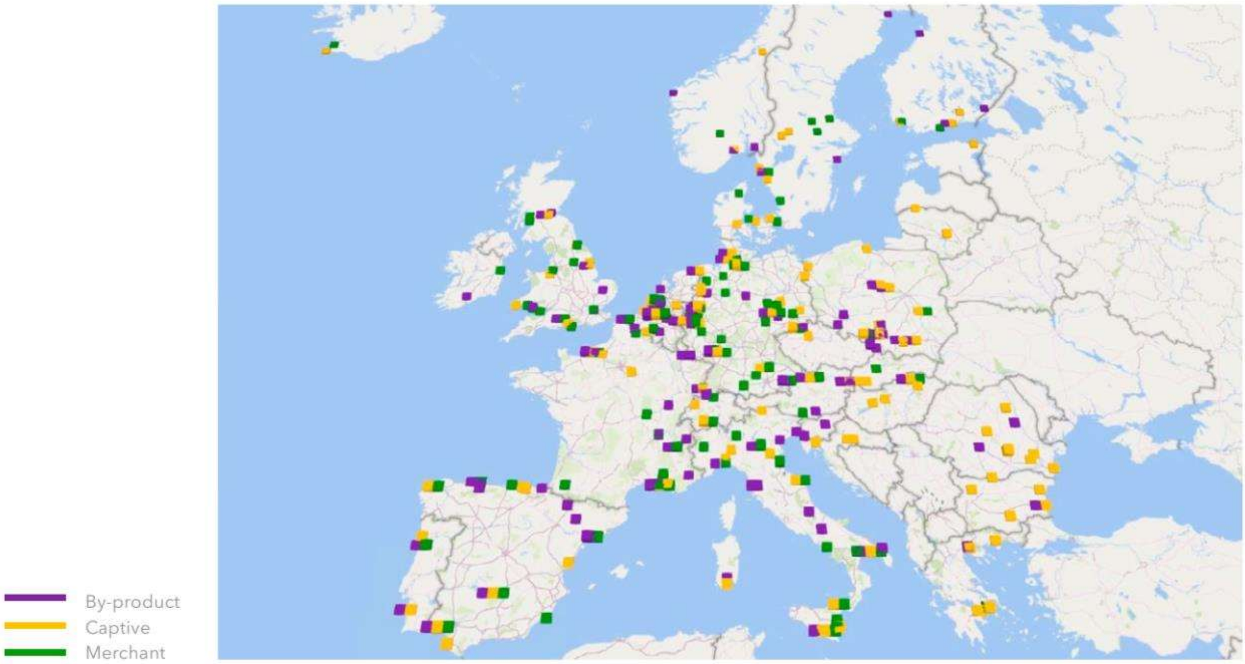

Figure 8 – Existing hydrogen production facilities in Europe (Pawelec et al., 2020)

These facilities are usually clustered at ports, near to other industries which consume hydrogen. Ports (either coastal or inland) are the most common locations for hydrogen hubs because they have excellent access to national and international transport and usually attract the build-up of chemical parks and other industrial zones.

Unfortunately, Europe's existing hydrogen industry is extremely polluting, with 95% of hydrogen produced using carbon-intensive steam methane reforming (SMR) from natural gas, known as 'grey hydrogen' (Certifhy, 2020), resulting in CO_2 emissions of between 70 and 100 million tonnes annually (European Commission, 2020a).

However, low-carbon methods exist to produce hydrogen, the most promising being ‘green hydrogen’ and ‘blue hydrogen’. The EU Certifhy project defines a low carbon threshold at 36.4g of CO_2 per Megajoule (MJ) of hydrogen produced and production methods below this threshold are certified low carbon, including green, blue and ‘purple hydrogen’. Together with grey and ‘black hydrogen’ (produced from coal gasification), these five methods make up a ‘hydrogen rainbow’, as shown in Figure 9.

Only green hydrogen is considered in this study as it is the only method that achieves life-cycle greenhouse gas (GHG) emissions close to zero (Certifhy, 2020).

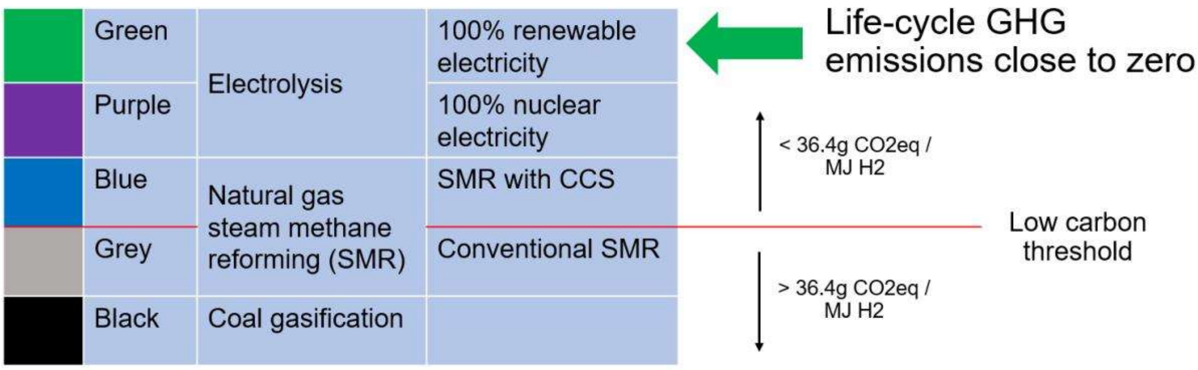

Figure 9 – The hydrogen rainbow (Certifhy 2020)

In 2018, the total installed green hydrogen electrolyser capacity in the EU, UK and Norway was 58 MW or 1.1 tonnes per hour, corresponding to just 0.1% of total hydrogen production (Pawelec et al., 2020). However, the 2020 EU Hydrogen Strategy (supported by a wave of NSR national hydrogen strategies and targets in Germany, the Netherlands, Denmark, Norway and, most recently, Scotland) aims to ambitiously ramp up green hydrogen electrolyser capacity to 6 GW by 2024 and 20 GW by 2030 (European Commission, 2020a). With technology rapidly advancing and climate targets fast approaching, this goal is increasingly achievable and unavoidable.

4.1.1 Geographic Scope

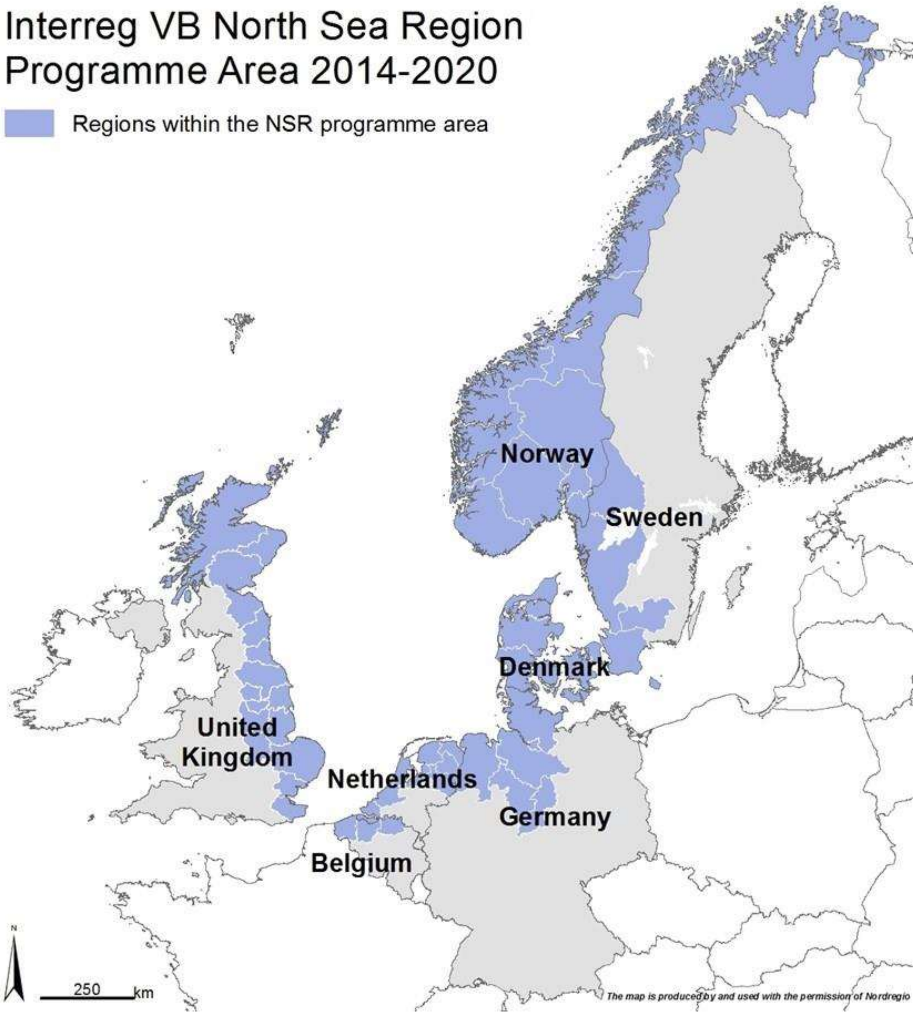

Figure 10 – North Sea Region Interreg (Nordregio 2021)

We use an extended version of the EU North Sea Interreg Region 2014-2020 definition to also include:

- Netherlands, Belgium, Scotland, Faroe Islands;
- the French departments of Nord, Pas de Calais, Somme, Seine Maritime, Eure, Oise and Ile de France (to encapsulate Channel and inland Seine ports);
- the German states of North Rhine Westphalia, Rhineland-Palatinate and Hesse (to encapsulate inland Rhinish ports).

4.2 Methodology

The analysis combined a review of H_2 projects at NSR ports with a summary of the traffic between Grimsby and each NSR port. The H_2 projects were used to assess NSR ports' H_2 development status and their potential for H_2 activities in the future.

The competitor/collaborator graphs are based on standard stakeholder analysis graphs, where different stakeholders are positioned as points on a graph where two axes represent their importance and influence.

For this analysis, stakeholders are different ports and the axes represent two indicators**: H_2 Development** and **H_2 Potential**. Furthermore, a third metric of evaluation is introduced by colouring the data points on the graph to represent each port's **Relation to Humber** ports. Because 184 ports were identified and analysed, there were too many data points to put every port on one chart. Instead, the ports were split according to their relation to Humber ports score and then shown on multiple charts.

Metric	Position	Description	Measurement
H_2 Development	X Axis	A function of the number of hydrogen projects in each port, their development stages and whether projects include bunkering as a hydrogen usage.	Score of 0 to 20.
H_2 Potential	Y Axis	A score summing in-port H_2-related industry.	Score of 0 to 20.
Relation to Humber	Data Points	A function of both offshore activity in each port and the total number of ship visits between that port and Aberdeen in 2019.	Score of 1 to 4, which determines colour of data point.

Table 2 – Explanation of port metrics in the Competitor and Collaborator Analysis

Existing and planned hydrogen projects at NSR ports were compiled for the purposes of this study.

4.2.1 H_2 Potential

The aim of collecting port data was to build a picture of which ports are best positioned to produce hydrogen in the future based on their industrial activity. This was then be compared to Grimsby and other Humber ports to place them in their regional context. A compendium of NSR ports was created to assess industrial characteristics of ports, linking them to existing and planned green hydrogen projects. All ports which were identified to have green hydrogen projects were included, as well as ports with specific industrial characteristics relevant to this study, namely **H_2-related industries** and offshore activity.

The term H_2-related industries is used in this project to refer to industrial processes which produce or consume hydrogen, as well as industries which share similar infrastructure to that required for the transport and storage of hydrogen. It is assumed that ports with existing H_2-related industries have a higher potential to become hydrogen hubs in the future than those which do not.

As shown in Figure 8, Hydrogen Europe categorises existing hydrogen production facilities as either merchant, on-site captive or by-product (Pawelec et al., 2020). As previously discussed, merchant hydrogen production is direct and dedicated production. Captive is the production of hydrogen for use in a specific purpose on-site and by-products. Captive hydrogen production exists in the manufacture of ammonia, methanol and hydrogen peroxide while by-product hydrogen arises from the chlor-alkali industry (Pawelec et al., 2020). Finally, industries using related infrastructure are natural gas terminals/processing plants, LNG terminals and oil terminals. Such infrastructure is included because oil and gas pipelines and storage facilities can be repurposed to carry liquid or gaseous hydrogen in a transition away from fossil fuels (European Commission, 2020a; Van Wijk & Chatzimarkakis, 2020). A list of H_2-related industries included in this study is summarised in Table 3.

Merchant/by-product	On-site captive	Similar infrastructure
Hydrogen production Chlor-alkali production	Ammonia Methanol Hydrogen Peroxide Refinery	Natural gas terminal / processing plant LNG terminal Oil terminal

Table 3 – List of H_2-related industries

Scoring was assigned to each port based on their H_2-related industry which then determined their position on the H_2 Potential axis of the competitor/collaborator analysis graphs. The existence of any of the above industries awards each port a score of 1 point per facility:

$$H_2\ Potential\ score\ = \Sigma\ (H_2 related\ industrial\ facilities)$$

For example, Gothenburg (SE) has two refineries, one LNG terminal and an oil terminal. Its H_2 Potential score is thus 2 + 1 + 1 = 4.

Data on industrial information was found using literature from chemical industry reports from private firms or associations, government reports, research institutes, individual port websites and Google Maps.

Hydrogen production facilities exclude production from other industries for which points are given that also involve merchant, by-product or on-site captive hydrogen production. These usually consist of SMR plants.

Ports are given an extra point for either offshore wind or Oil and Gas (O&G). A maximum of two points can be awarded if a port services both offshore wind and O&G. Ports that have access to large amounts of renewable energy resources are presumably better placed to be producing and exporting hydrogen, if the hydrogen is not produced offshore. However, the port's potential for production and export would be limited by available industrial space to develop electrolysers and storage and harbour characteristics such as size and depth.

4.2.2 H_2 Development

The first step of this report was to gain a holistic understanding of NSR green hydrogen projects of all stages, with specific attention to bunkering projects. Data was collected from a wide range of sources: from press releases with little or no detail, to mature projects under construction and existing and operational facilities. This information was then used to map the key players, or hubs, in the NSR and the roles of a diverse range of ports: from those which are planning or talking about hydrogen to those which have already installed green hydrogen infrastructure for production or bunkering.

This part of the study began with the collection of projects, which were included based on the following conditions:

- They consisted of the production or usage of green hydrogen, based on the definition of the EU Certifhy project, as shown in Figure 9 (Certifhy, 2020);
- They were located in one or more NSR ports (as defined in Section 4.1.1).

Projects were identified from publicly available literature such as technical reports by technical universities, governments and research institutes, investment plans, conference slides and press releases. The resulting projects were categorised into four development stages: completed, under construction, funded and concept, as defined in Table 4.

Development stage	Definition
Completed	The project has resulted in operational green hydrogen production or usage.
Under construction	Construction has begun or planning permission has been received.
Funded	Public or private investment has been secured.
Concept	The project is envisaged, planned or studied without investment or funding yet secured.

Table 4 – Definitions of development stages of green hydrogen projects

Further information was recorded for each project where available. For hydrogen production projects, electrolyser capacity (MW) and quantity (tonnes/year) were noted. For all projects, (planned) year of completion, hydrogen storage or supply type and intended usage sectors were recorded when stated. Typical hydrogen storage or supply types were GH_2, LH_2, liquid organic hydrogen carriers (LOHC) or containerised (either GH_2 or LH_2). Typical sectors for usages included industry, road vehicle fuel, electricity grid balancing/storage, blending with the natural gas network, heating, refinery processes, production of e-fuels and vessel bunkering.

For each port, the scoring system for H_2 Development is a function of the green hydrogen project number, hydrogen usage and development stage. Ports are awarded 1 point for each non-bunkering project and 2 points for each bunkering project. Scores were not weighted by electrolyser capacity because this data was not available for a considerable number of projects. These scores are then multiplied, for each project, by a value determined by the project development stage(s). The multipliers are 1 for ‘Concept’, 2 for ‘Funded’ and 3 for ‘Under construction’ and ‘Completed’, as summarised below. This way, H_2 Development is an accurate representation of not only the number of projects found in each port but also their nearness to realisation. Furthermore, bunkering projects have been emphasised in the scoring due to the nature of this project. Multipliers are added to reflect the maturity of projects. Projects with intended maritime usage of green hydrogen are worth double.

Project scores:

Non-bunkering project = 1

Bunkering project = 2

Development stage multipliers:

x1 Concept

x2 Funded

x3 Under construction

x3 Completed

$$H_2\ Development\ score\ = \Sigma(project\ score \times development\ stage\ multiplier)$$

As examples, Ijmuiden (NL) has one concept non-bunkering project and one funded bunkering project so its H_2 Development score is (1x1) + (2x2) = 5; whereas, Le Havre has one under construction non-bunkering project, so its score is 1x3 = 3.

4.2.3 Example of Port Relationships for UK North Sea Ports: Relation to Humber

In the competitor/collaborator graphs, it was important that some indicator of port relationships to Humber be included so that the analysis is tailored to the Humber's specific case. The metric describes vessel traffic between Humber and NSR ports. Humber in this case consists of the Associated British Ports (ABP) Humber ports of Grimsby, Immingham, and Hull. Smaller ports in the Humber region such as Goole were excluded from this definition.

Ship visit data to Humber ports in 2019 was used to estimate the yearly (pre-Covid-19) trading relationship between Humber and other NSR ports. First, NSR ports were individually filtered in the excel document and then the details of visits to Humber were recorded, with respect to the port origin and ship types.

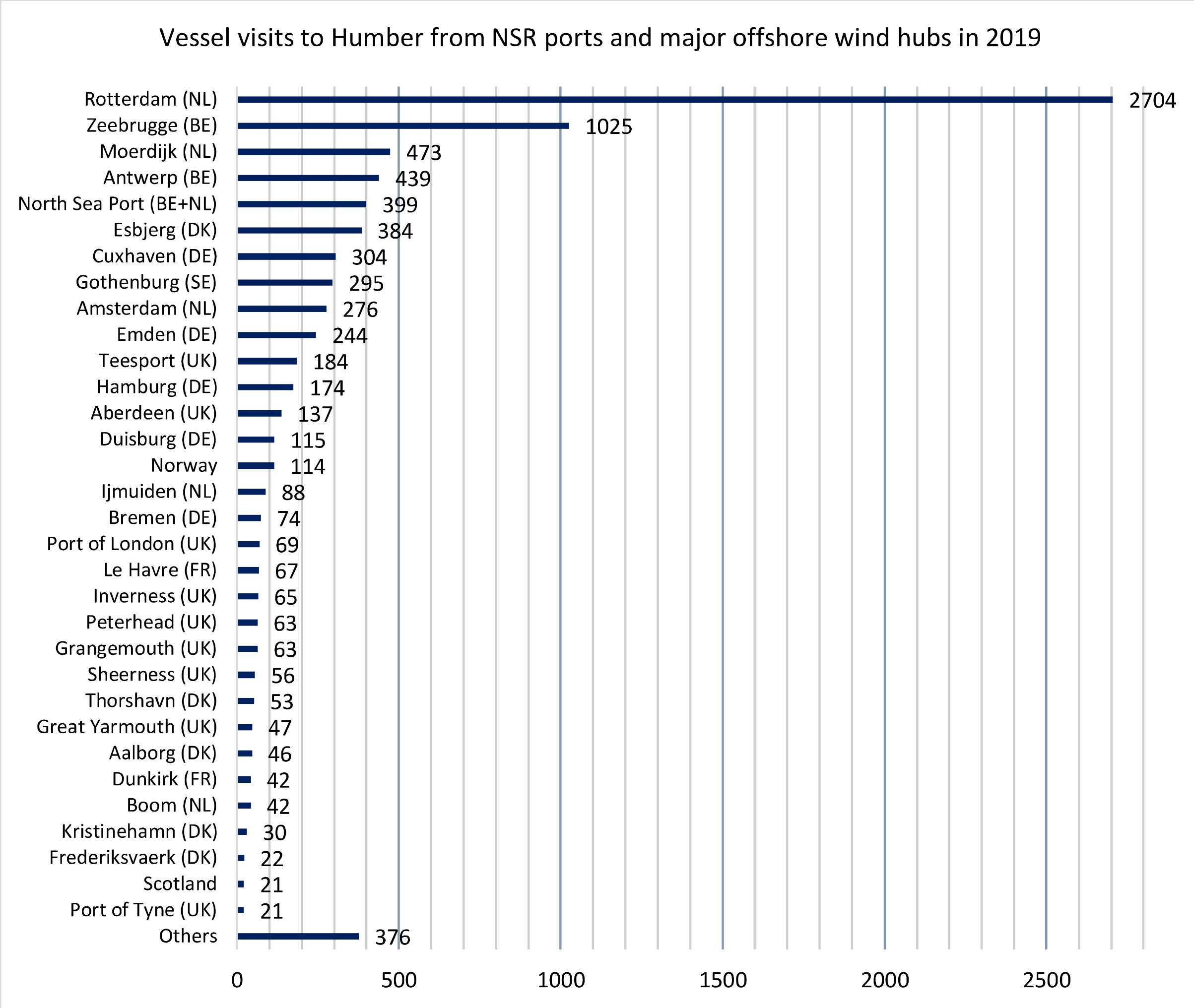

Figure 11 – Vessel visits to Humber from NSR ports and major offshore wind hubs in 2019

To simplify the above traffic data into a point scoring system while reflecting the distribution of visits, the data was simplified into a score of between 0 and 4, as shown in Table 5.

Number of visits to Humber in 2019	Port visits score
0	0
1-9	1
10-99	2
100-999	3
>1000	4

Table 5 – Port visit score allocation

4.2.4 Possible Improvements

The Ports Collaborator / Competitor Workshop highlighted that displaying average H_2 Development scores (score per number of projects) would be more accurate for comparing ports. This was, however, not adopted because the number of projects in one port is also a strong indicator of the scale of development. Furthermore, the average scores weighted heavily in favour of small ports with one high-scoring project, distorting the significant roles played by major ports such as Rotterdam and North Sea Port (encompassing Ghent (BE), Vlissingen (NL) and Terneuzen (NL)).

The H_2 Potential score does not include blue hydrogen projects underway in each port. While the scope of this study is strictly green hydrogen, it would be valuable to include blue hydrogen projects in the calculations to reflect infrastructure crossover (examples being storage, pipelines and bunkering). Since fossil-derived hydrogen is already included in the H_2 Potential score, it is only logical that blue hydrogen should too. This could be easily integrated into the existing methodology by, for example, awarding ports an additional point for each blue hydrogen project. It would, however, require additional resources to research blue hydrogen projects.

4.3 Results

4.3.1 Collaborator / Competitor Graphs

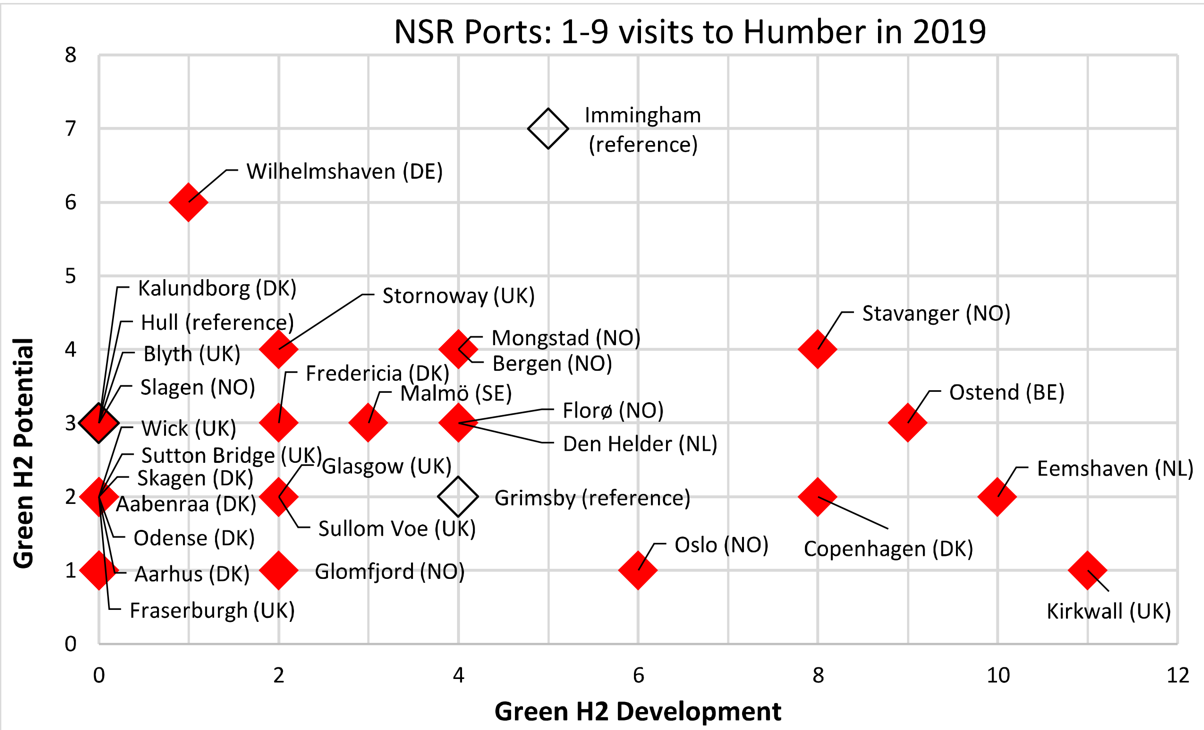

Figure 12 – Collaborator / competitor graph for NSR ports with 1-9 visits to Humber in 2019

Several ports score highly for H_2 Development that have relatively low H_2 Potential scores (Kirkwall, Eemshaven, Ostend, Stavanger and Oslo). These are regional first movers in building up hydrogen infrastructure, with Kirkwall, Ostend, Copenhagen and Oslo, Stavanger each with two projects in green hydrogen production for maritime use and Eemshaven, which boasts four green hydrogen projects as an important component of the North Netherlands Hydrogen Valley, along with Groningen, Emmen and Delfzijl.

Ports scoring the minimum of 1 for H_2 Potential and 0 for H_2 Development are unlabelled on the above graph. They consist of Calais (FR), Dover (UK), Halmstad (SE), Kiel (DE), Klaksvik (DK), Kvinesdal (NO), Lübeck (DE), Rendsburg (DE). These ports have homogenous functions; passenger transport and Roll-on/roll-off freight vessel (Ro-Ro) for Calais, Dover, Kiel and Lübeck and offshore wind or O&G for the remainder.

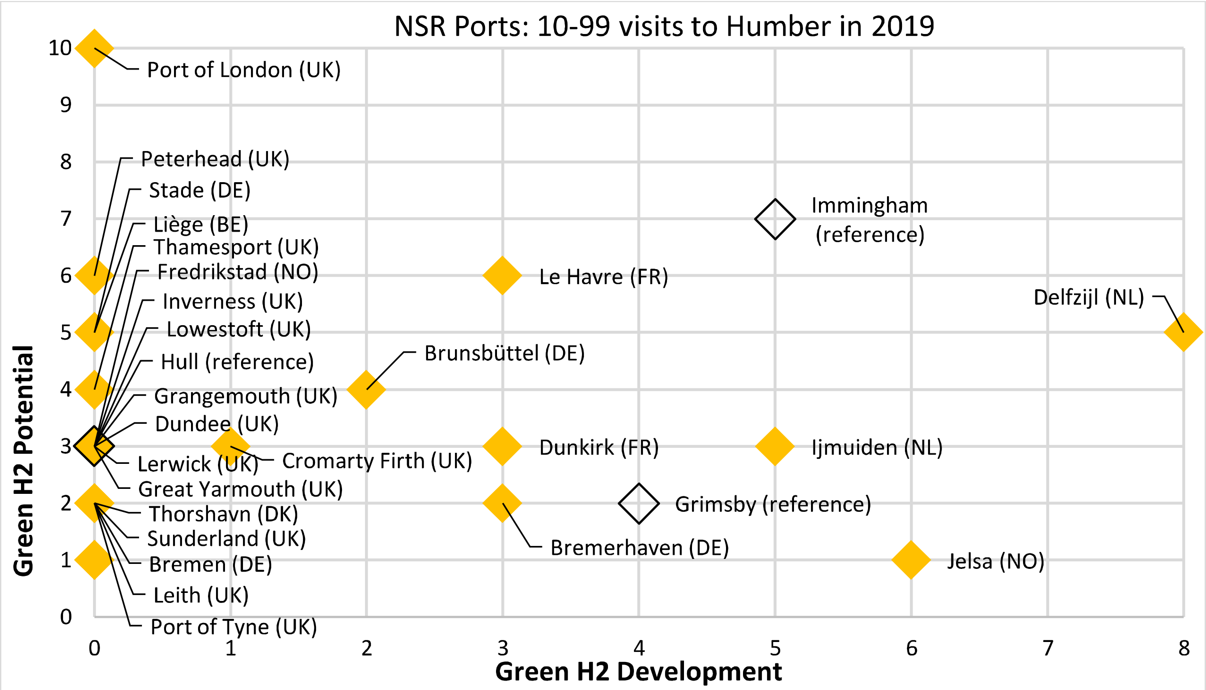

Figure 13 – Collaborator / competitor graph for NSR ports with 10-99 visits to Humber in 2019

Humber ports see moderate visits from ports with planned large-scale green hydrogen production on scales with Immingham. Le Havre and Dunkirk are the site of two Air Liquide 200 MW electrolysers projects, currently under construction and expected to be online by 2025 and 2023 respectively. The hydrogen will feed into Air Liquide's existing pipeline infrastructure to be used for refinery processes and other industries. Delfzijl scores highly for H_2 Development, being a key site for much of the North Netherlands Hydrogen Valley. Ijmuiden is a Dutch offshore construction and Operations & Maintenance (O&M) hub with modest development, including a funded maritime hydrogen project.

Humber ports have a moderate connection to the western Norway port of Jelsa. This is a significant hydrogen hub for its small size. The port services the world's first liquid hydrogen-powered vessel, Norled's *Hydra*. This vessel is hydrogen-ready but is currently operating on battery power until hydrogen import becomes available in tube trailers from Linde's 24 MW electrolyser in Leuna, near Leipzig, Germany, in the near-future. Gen2 Energy has plans for a 10 MW electrolyser in Jelsa operational by 2023/24, ultimately planned to be scaled up 300 MW.

At the right-hand side of the graph are many ports which score zero for H_2 Development, with varying levels of H_2 Potential. These can be described as ports that have not yet crossed the starting line in terms of exploiting the potential for green hydrogen production. Notable among these, is the Port of London, which has seen no green hydrogen development despite great potential. In fact, Port of London is the most underperforming port analysed. This presents the Humber with a great opportunity to establish itself as the leading UK producer of hydrogen, despite having somewhat less potential than Port of London.

Ports scoring the minimum of 1 for H_2 Potential and 0 for H_2 Development are unlabelled on the above graph. They consist of Boom (BE), Frederiksvaerk (DK), Ipswich (UK), Kristinehamn (SE) and Sheerness (UK).

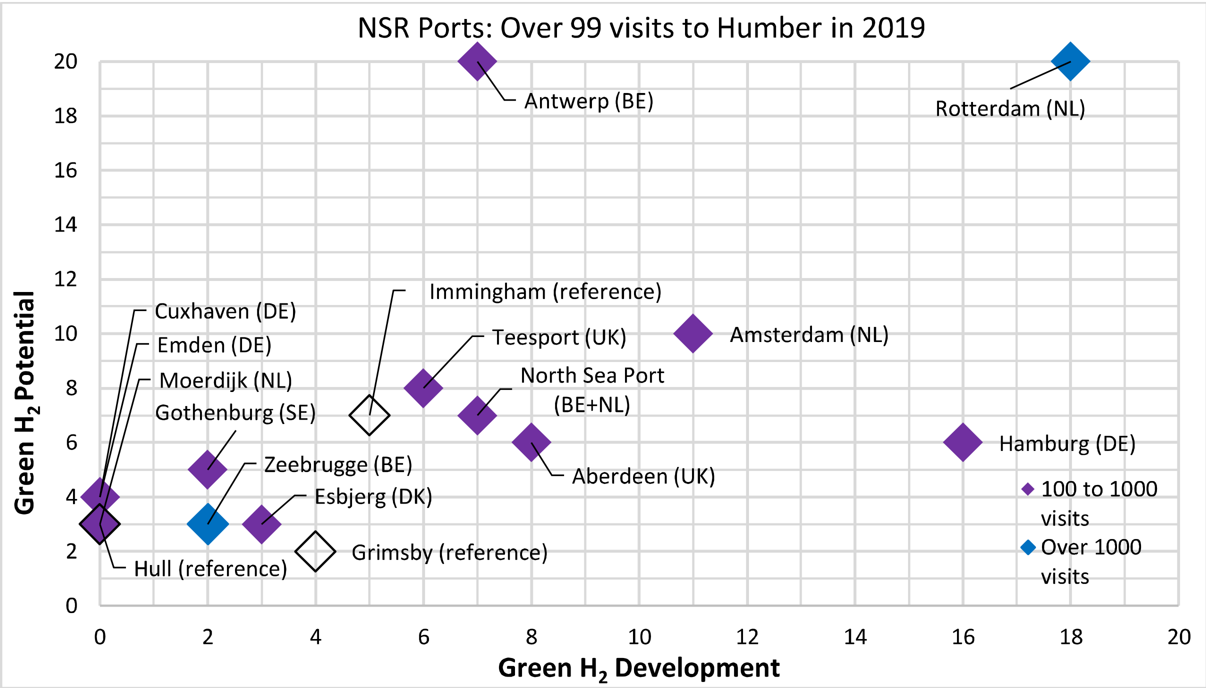

Figure 14 – Collaborator / competitor graph for NSR ports with over 99 visits to Humber in 2019

Ports with the highest visits to the Humber are large ports with diverse scores for H_2 Potential and Development. On the highly development end are Rotterdam and Hamburg. The Port of Rotterdam (which here also encompasses Europoort, Vlaardingen, Hook of Holland, Maasdijk, Botlek and Dordrecht) is the largest port in Europe (Port of Rotterdam, 2021) and the highest-scoring port analysed, with a massive array of H_2-related industry consisting of 4 hydrogen production facilities, 5 refineries, 5 oil terminals as well as chlorine, hydroxide peroxide production and an LNG terminal. The development of green hydrogen is widespread, with 9 projects including 5 for maritime use. Rotterdam is obviously a regional heavyweight and will undoubtedly continue its position as a bunkering centre into the hydrogen transition. Hamburg scores similarly to Rotterdam in terms of development but lags behind on potential. Nevertheless, it can also be expected to be a large regional hydrogen bunkering hub.

In the mid-range group of H_2 Development are Amsterdam, Antwerp, North Sea Port, Aberdeen and Teesport. Antwerp leads in H_2 Potential, scoring the same as Rotterdam and being Europe's second largest port. This is because of 4 refineries, 6 oil terminals, 3 hydrogen production sites, 2 hydrogen peroxide production sites, chlorine, ammonia, methanol and an LNG terminal. The port has not yet seen development on the same scale as Rotterdam but is advanced in pilot maritime hydrogen projects, with one completed multi-modal bunkering station built by CMB Tech.

The Humber ports have very high traffic with Zeebrugge, which recently announced plans to build a 30 MW electrolyser by 2023 (The Brussels Times, 2021) and signed an MoU with Antwerp to import green hydrogen from Chile (Port of Antwerp, 2021). Ship traffic mainly consists of Ro-Ro Freight, Roll-on/roll-off freight and passenger vessel (Ro-Pax), Car Carriers and Container Carriers so there may be significant potential for collaboration on port-to-port voyages.

It is important to note that Hamburg and Cuxhaven (as well as Bremerhaven and Wilhelmshaven) have ferry links to the important offshore wind O&M hub of Heligoland, which is the base for the planned Aquaventus project for at least 300 MW of offshore hydrogen production.

4.3.2 Green Hydrogen Production in North Sea Region Ports

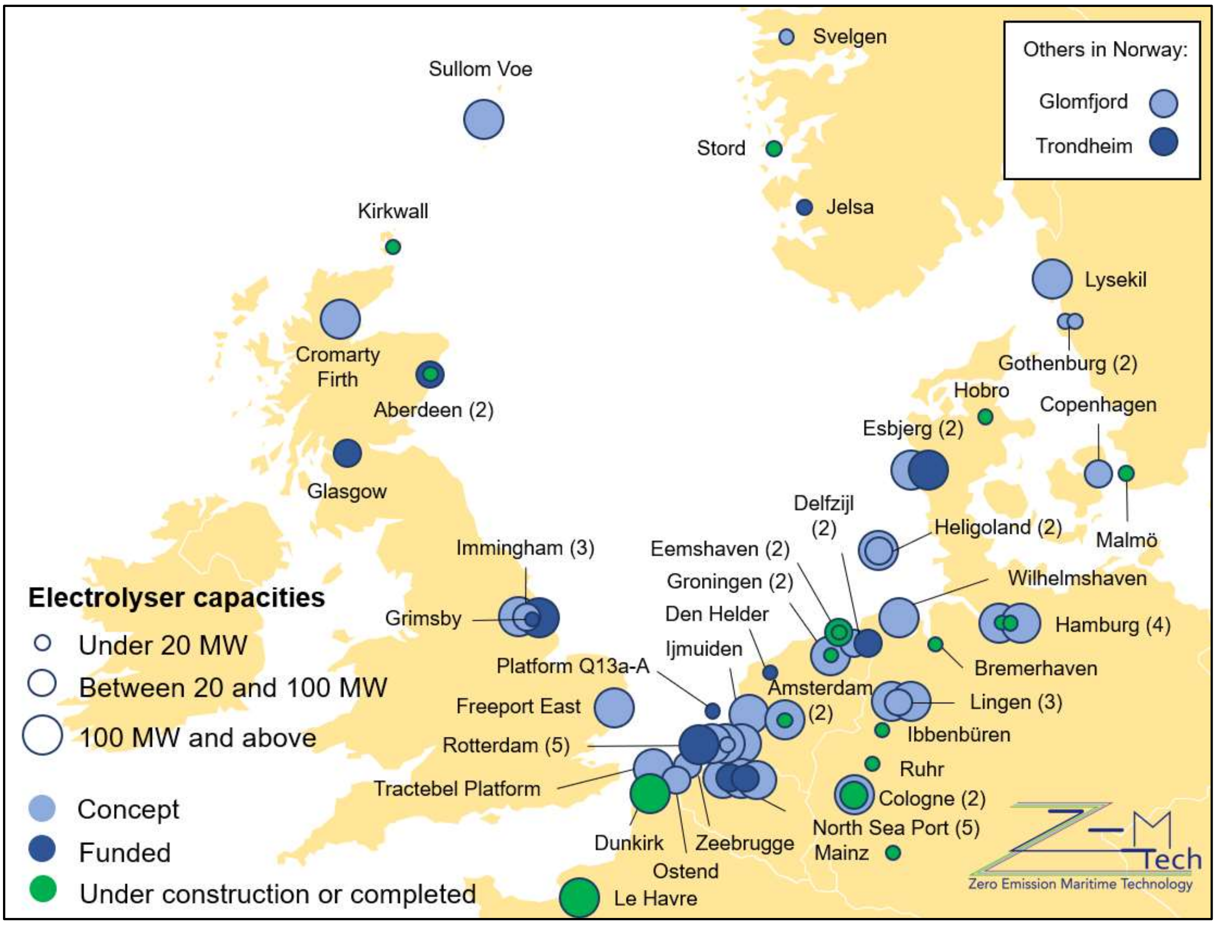

Figure 15 – Map of green hydrogen production in North Sea Region ports

The map shows electrolyser production projects in the NSR where planned capacity has been specified. Because projects where capacity is not yet specified are not shown, the actual number of projects is greater.

Electrolyser development is widespread in the NSR region, especially with dense clustering in and around the southern Netherlands and northern Belgium. Another significant development hub is located in northern Netherlands and north-eastern Germany.

In the UK, the most extensive planned production is in the Humber, while Aberdeen has the most developed electrolyser projects.

4.3.3 Collaboration with North Sea Region ports

Key ports in the NSR were placed in the table below to summarise the potential for collaboration or competition with Humber ports. Only ports with 100 or more visits to Humber in 2019 and/or with offshore wind O&M capacity 50 MW or more were included. For reference, Grimsby has a H_2 Potential Score of 2, a H_2 Development Score of 4 and 3407 MW of O&M capacity (more than any other port analysed). For each port, any ship types that visited over 10 times are specified.

Transit distance from Humber was included as a variable because it may identify ports that could compete as Service and Operations Vessels (SOVs) and Crew Transfer Vessel (CTV) H_2 bases. However, because SOVs and CTVs would operate from the nearest port, little competition is envisaged.

An analysis was conducted (summarised in Table 6) identifying the specific types of collaboration possible between Grimsby and other NSR ports.

Port	**Relation to Humber (visits in 2019)**	**O&M capacity (MW)**	**Transit distance under 100 nm**	**Pot Score**	**Dev Score**	**Ship types visiting (if >10 ships)**	**PTP priority collab.**	**Offshore collab**
Aberdeen (UK)	137	143.2		6	7	Tanker		Y
Amsterdam (NL)	276	0		10	11	General Cargo, Tanker, Chemical Tanker		
Antwerp (BE)	439	0		20	9	Tanker, General Cargo, Chemical Tanker, LPG		
Barrow-in-Furness (UK)	0	1472		2	0			Y
Cuxhaven (DE)	304	0		4	0	Ro-Ro Freight, General Cargo, Car Carrier		
Eemshaven (NL)	2	2050		2	10			Y
Emden (DE)	244	1214		4	0	Car Carrier, Ro-Ro, General Cargo		Y
Esbjerg (DK)	384	945		3	3	Ro-Ro Freight, Car Carrier		Y
Fraserburgh (UK)	1	605		3	0			Y

Freeport East (UK)	0	165.5 (Harwich)		4	1			Y
Gothenburg (SE)	295	0		5	2	Ro-Ro Freight, Tanker		
Great Yarmouth (UK)	47	462	Y	3	0			Y
Grenaa (DK)	0	399.6		2	0			Y
Hamburg (DE)	174	0		6	16	General Cargo, Ro-Ro Freight, Container, Tanker		
Heligoland (DE)	0	688.4		2	3			Y
Hvide Sande (DK)	0	406.7		2	0			Y
Ijmuiden (NL)	88	357		3	5	General Cargo		Y
Lemmer (NL)	0	263.5		2	0			Y
Lowestoft (UK)	10	966	Y	3	0			Y
Malmö (SE)	6	110.4		3	3			Y
Moerdijk (NL)	473	0		3	0	General Cargo, Container		
Mostyn (UK)	0	909.6		3	0			Y
Newhaven (UK)	0	400.2		2	0			Y
Norddeich (DE)	0	1559		2	0			Y
North Sea Port (BE)	399	752 (Vlissingen)		7	7	General Cargo, Container, LPG, Tanker, Chemical Tanker		Y
Ostend (BE)	2	3012		3	9			Y
Ramsgate (UK)	0	1070		2	0			Y
Rødby (DK)	0	201		2	0			Y
Rømø Havn (DK)	0	288		2	0			Y
Rørvig Havn (DK)	0	605		2	0			Y
Rotterdam (NL)	2704	0		19	18	Ro-Ro Freight, Ro-Pax, Container, General Cargo, Tanker, Car Carrier, LPG, Chemical Tanker, Refrigerated	Y	
Sassnitz (DE)	0	1071.5		2	1			Y
Sutton Bridge (UK)	3	135		2	0			Y

Teesport (UK)	184	65		8	6	Tanker, Chemical Tanker, General Cargo		Y
Urk (NL)	0	263.5		2	0			Y
Wells-next-to-sea (UK)	0	316.8	Y	2	0			Y
Wick (UK)	7	588		2	0			Y
Wilhelmshaven (DE)	8	110.7		6	1			Y
Workington (UK)	0	174		3	0			Y
Zeebrugge (BE)	1025	0		2	1	Ro-Ro Freight, Ro-Pax, Car Carrier, Container, General Cargo	Y	

Table 6 – Summary of potential for Humber ports collaboration and competition with NSR ports and offshore wind O&M hubs

The outcomes of Table 6 can be summarised as follows:

- The workshop produced a consensus that every port could potentially be both a collaborator and competitor, while ABP member ports are considered as collaborators by default.
- Three forms of collaboration were identified:
  - Point-to-point (PTP) collaboration: Developing bunker facilities at each end of an Origin-Destination pair, including harmonisation of procedures, technical standards, compatible bunkering infrastructure etc. Ro-Ro Freight, Ro-Pax vessels and Car Carriers are best suited to this form of collaboration because they usually sail on fixed routes.
  - R&D project collaboration: Partnership projects seeking to win mutually beneficial public or private contracts to advance the state of maritime hydrogen uptake in each port.
  - Offshore collaboration: Projects specifically oriented to the offshore wind sector, expected to be an early adopter of maritime hydrogen.
- ABP is in a privileged position to convene different stakeholders to promote collaboration because of the large group of ports already in the holding company which can levy considerable influence.
- The nature of alternative fuels means that many more bunkering locations will be required than for fossil fuels. This adds more pressure for collaboration between ports which can be achieved through international initiatives such as the Clydebank Declaration and EU Green Ports (Mayet, 2017; European Commission, 2020b).
- Ports with potential for collaboration:
  - Collaboration between ABP and Teesport is already underway.
  - Similarly, Emden is a major offshore wind O&M hub like Grimsby.

- Aberdeen has a similar port function to Grimsby (Offshore Service Vessels, OSVs) but is more O&G oriented. Green hydrogen production is expected to be large in Aberdeen.
- Liverpool and Vancouver are interested in collaboration for offshore wind hydrogen projects

- Cuxhaven is a PTP Car Carrier link with Grimsby's carport. This could be a potential candidate for a zero emissions "Clydebank Green Corridor" route.
- Zero emissions fuelling in offshore wind is very much in its infancy and, as such, new port ecosystems will need to be developed. This will involve not only the physical infrastructure required but also the training, standards and regulations involved in the novel use of technologies. It is important that these are harmonised across the sector to avoid market barriers due to incompatibility and reduce duplication of effort.
- Ports servicing large offshore wind O&M capacity (in MW) are good candidates for collaboration with Grimsby due to similar port operations and functions: Oostende, Eemshaven, Norddeich, Barrow-in-Furness, Ramsgate, Emden, Lowestoft, Fraserburgh Harbour, Esbjerg.
- Similarly, ports local to Grimsby are potential collaborators, along the east coast of the UK: Newhaven, Ramsgate, Brightlingsea, Harwich, Great Yarmouth, Lowestoft, Wells-next-the-sea, Sutton Bridge, Hartlepool, Aberdeen, Peterhead, Fraserburgh Harbour and Wick.
- Zero Emission fuel first movers: Ports that have shown particular interest into the transition to ZE fuels. Operation Zero signatories: ABP, Aberdeen Harbour, Port of Esbjerg, Port of Cromarty Firth, REBO-Ostend. Antwerp is another first mover because of the Windcat hydrogen-powered CTV project.

4.3.4 Detail on Collaboration with Offshore Ports

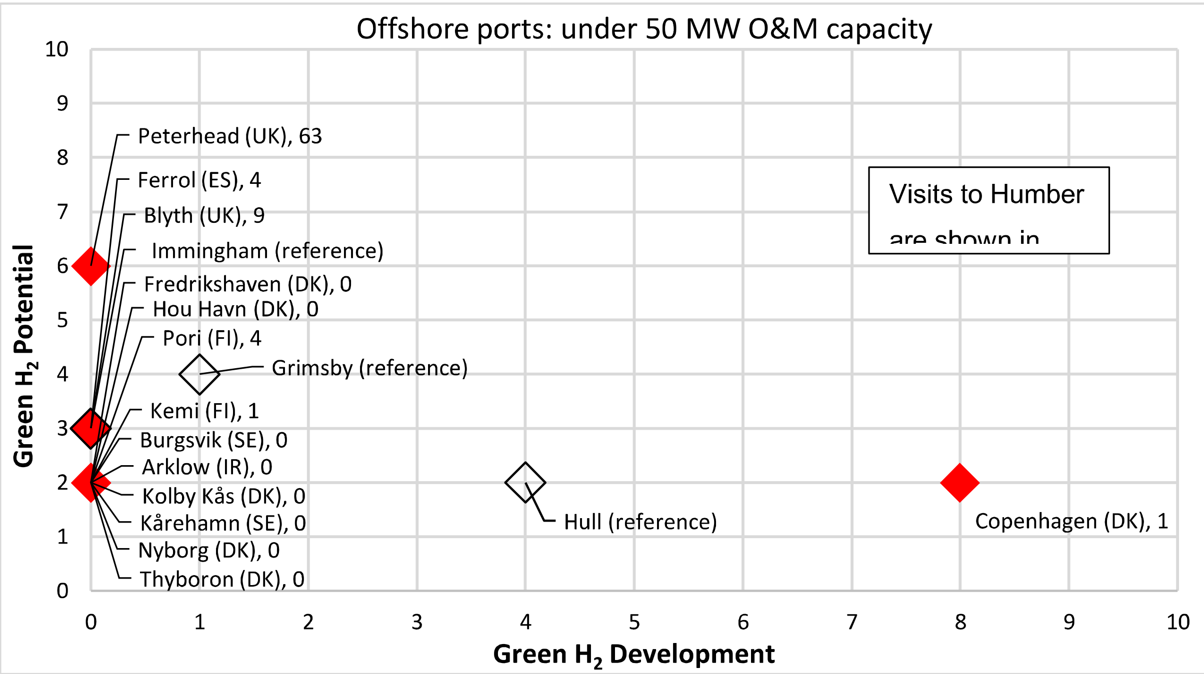

Figure 16 – Collaborator / competitor graph for offshore hubs with under 50 MW O&M capacity

Peterborough could be expected to develop a zero emissions offshore bunkering system. It has moderate traffic to Humber so collaboration would be advised. It's low overall O&M capacity would make it a small-scale up-taker of offshore demand unless this capacity increases significantly in future with the roll out of floating offshore wind.

Copenhagen stands out as an offshore wind port with high H_2 Development but low O&M capacity. Because of its long distance from Humber and very low vessel traffic, it is not a likely partner for collaboration.

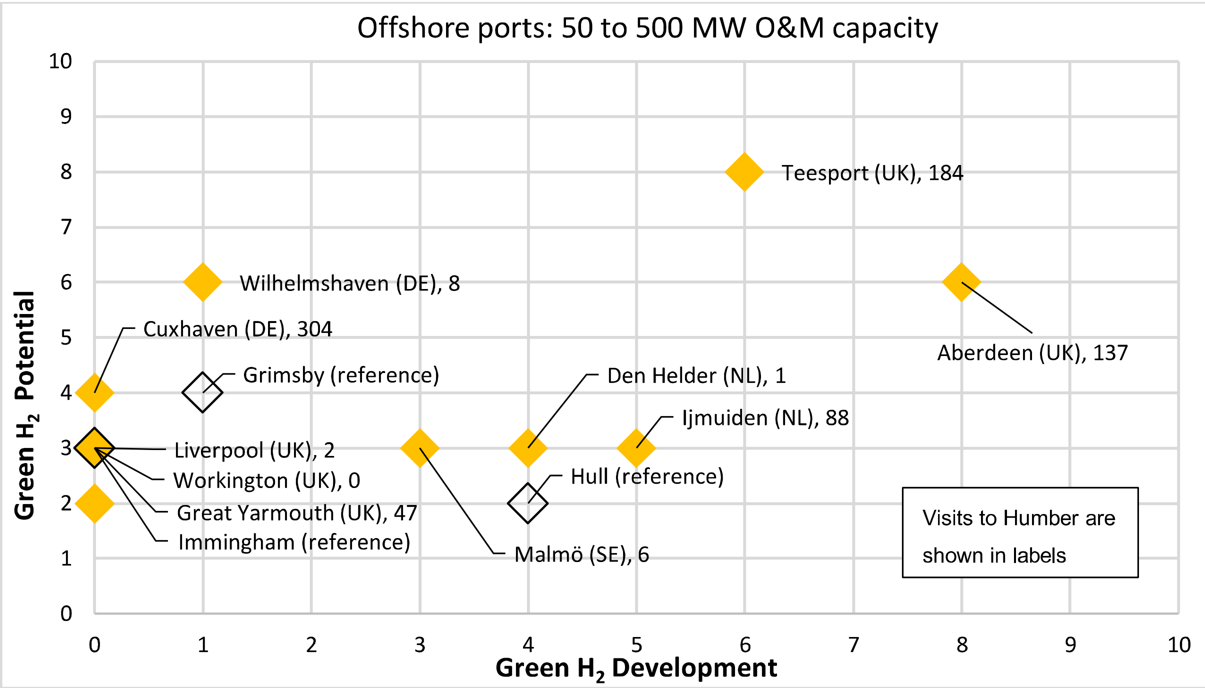

Figure 17 – Collaborator / competitor graph for offshore hubs with between 50 and 500 MW O&M capacity

Teesport and Aberdeen are the most likely collaboration partners, each having high Potential and Development. Aberdeen is the base for the Dolphyn project for hydrogen generation on an offshore wind turbine. Due to their situation on the UK's East Coast, substantial vessel traffic with Humber and significant O&M capacity, the ports would be good candidates for collaboration. More work could be done to analyse the ship types travelling between Grimsby and these ports to assess whether the potential for SOV and CTV alternative fuelling is possible.

Ports that score (0,2) are unlabelled in the graph and are Birkenhead (UK), Borkrum Hafen (NL), Brightlingsea (UK), Gedser (DK), Grenaa (DK), Hvide Sande (DK), Lemmer (NL), Newhaven (UK), Rødby (DK), Rømø Havn (DK), Sutton Bridge (UK), Urk (NL), Wells-next-to-sea (UK).

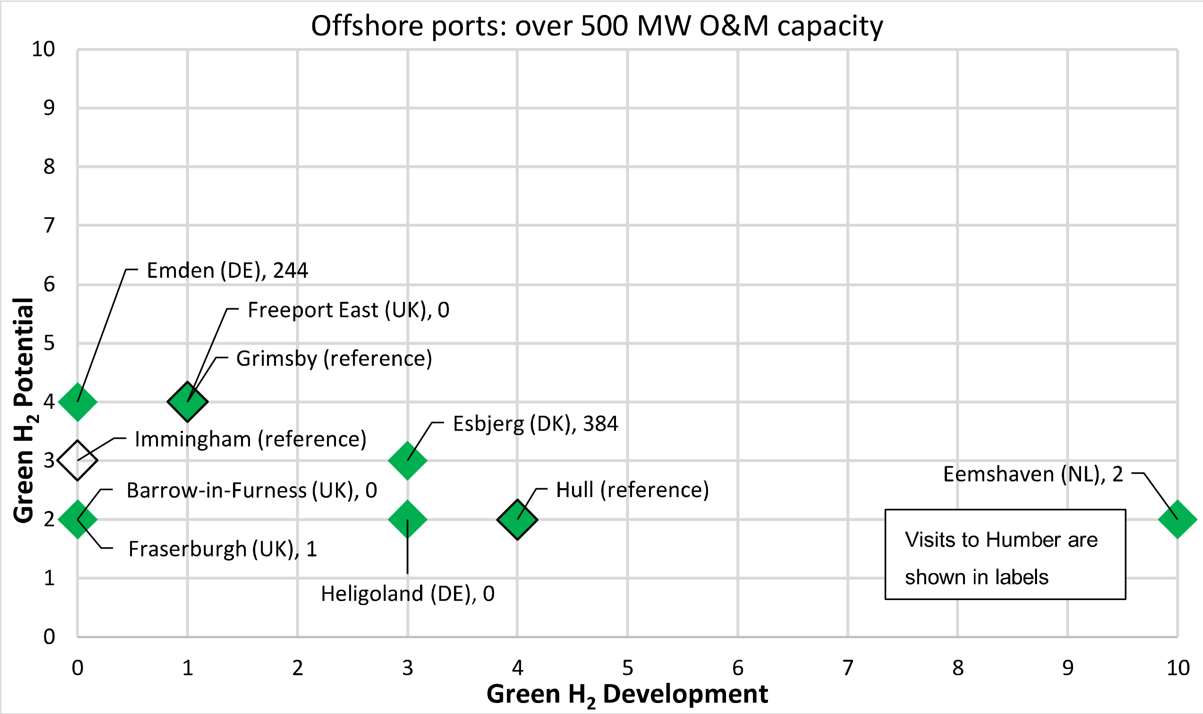

Figure 18 – Collaborator / competitor graph for offshore hubs with over 500 MW O&M capacity

Esbjerg has large plans for green hydrogen production in-port. The high traffic between Esbjerg and Humber indicates an opportunity for collaboration.

Heligoland is expected to be a major pioneer of offshore hydrogen production because it is home to the Aquaventus project which plans to develop a fully zero emissions offshore sector. Ports in the surrounding area such as Wilhelmshaven, Eemshaven, Emden, Norddeich, Cuxhaven and Esbjerg will likely see knock-on hydrogen economy effects and diffusion of know-how. However, the UK has a head start with regards to large-scale offshore generation already in place or under construction and development of hydrogen offshore.

Freeport East (Harwich) has a large O&M capacity but no traffic with Humber. Despite this, Harwich has modest potential for green hydrogen in future and would be a good candidate for offshore zero emissions collaboration along the East Coast.

4.4 Analysis

4.4.1 Hydrogen Export to Norway

It is somewhat surprising to see that Humber ports have a connection to Jelsa, which is a small Norwegian port that is home to an emerging hydrogen economy despite its size. The relation consists of 12 visits in 2019, 6 visits each from the Bulk Carriers *Splittnes* and *Sandnes*.

A landmark MoU for hydrogen shipment from Gen2 Energy in Western Norway to Cromarty Firth was announced in May 2021 (Gen2 Energy, 2021). The hydrogen will be exported from several planned sites, at

Jelsa, Mosjøen (both ports) and Meråker, with hydrogen from the latter presumably exported from the ports of Stjørdal or Trondheim. A similar shipment agreement between Gen2 Energy and Grimsby, would put Grimsby into direct competition with Cromarty Firth for imports. Gen2 Energy is also part of the Zefyros consortium, which aims to build an offshore electrolyser off the Norwegian coast.

The distribution of ship types is known for all Norwegian visits to and from the Humber, as shown below.

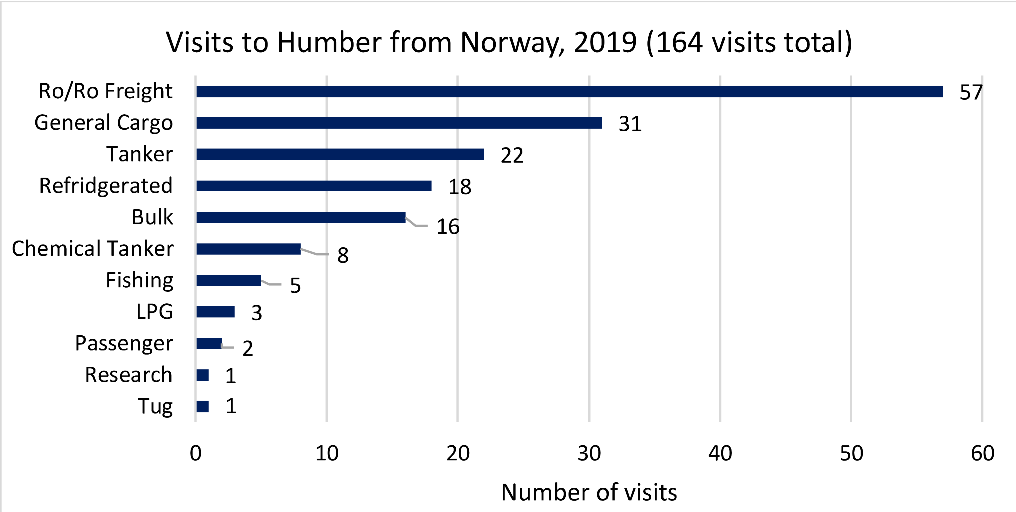

Figure 19 – Visits to Humber from Norway in 2019 by ship type

From this graph, we can see that the highest number of visits come from Ro-Ro Freight vessels. It is unclear whether Jelsa's LH_2 truck import from Germany, will include transport by sea on Ro-Ro Freight vessels. If not, it could be foreseen that transport of LH_2 by truck in Ro-Ro Freight vessels could arise soon to cut journey times. More work must be done to assess regulation feasibility. Even with transport by sea, it is still a journey made mostly by road of over 1400 km (Google Maps, 2021). Entirely by road, this journey length increases to over 1800 km.

Norway is more advanced in hydrogen usage for maritime vessels than other countries studied, so export to Norway could be a lucrative market for excess hydrogen production in the Humber. It could present hydrogen producers with a guaranteed early off-taker before local demand is established.

Immingham is developing significantly larger capacity for green hydrogen production than Norwegian ports, with 100 MW of funded capacity and another 120 MW of conceptual capacity. Only the ports of Glomfjord and Trondheim come close to this scale, with 41 MW (concept) and 20 MW (funded), respectively. The journey from Immingham to Jelsa would be entirely seaborne, cutting delivery times enormously.

4.4.2 Clydebank Green Shipping Corridor

All NSR countries are signatories to the Clydebank Declaration, which strives to establish "green shipping corridors – zero-emission maritime routes between 2 (or more) ports." (UK Government, 2021b). Collaboration with other ports to initiate a zero-emissions PTP route in the NSR would be an option to push forward and demonstrate decarbonisation of short sea shipping routes. This requires communication with other ports from Clydebank Declaration signatory countries to align regulations, standards and coordinate PTP operations.

Small, short-sea General Cargo vessels are the most suitable ships for hydrogen propulsion. Such visits come to the Humber overwhelmingly from the Netherlands, Germany and Belgium; specifically, Amsterdam, Antwerp, Bremen, Ruhr, Hamburg, Ijmuiden, Moerdijk, North Sea Port and Rotterdam. Where these visits are PTP routes, opportunities for Green Corridors can be explored in more detail.

Cuxhaven has a Car Carrier PTP connection with Grimsby. While this fairly large vessel type would pose complications to completely convert using existing technology, the opportunity for demonstrating partial zero emissions retrofit or a zero emissions new build should be explored.

4.5 Conclusions

4.5.1 Trends in the NSR Maritime Hydrogen Economy

Ports with high H_2 Development but low H_2 Potential are expected to be reliant on collaboration with nearby ports that will have larger hydrogen production capacity. However, the nature of alternative fuels means that many more bunkering locations will be required than for fossil fuels. This increases opportunities for collaboration between ports which can be achieved through international initiatives such as the Clydebank Declaration and EU Green Ports (Mayet, 2017; European Commission, 2020b).

Despite the expected higher number of bunkering locations, the density of traffic in the North Sea and the consolidation of industry in largest ports creates the risk that hydrogen production could be monopolised by Rotterdam and Antwerp and shipped out to bunkering locations. Collaboration between ports and other large NSR producers such as Le Havre, Dunkirk, Delfzijl and Hamburg could ensure that this does not occur.

4.5.2 Opportunities for Collaboration

Every port analysed could potentially be both a collaborator and competitor, while ABP member ports are considered as collaborators by default. Three forms of collaboration were identified:

- Point-to-point (PTP) collaboration: Developing bunker facilities at each end of an Origin-Destination pair, including harmonisation of procedures, technical standards, compatible bunkering infrastructure etc. Ro-Ro Freight, Ro-Pax vessels and Car Carriers are best suited to this form of collaboration because they usually sail on fixed routes.
- R&D project collaboration: Partnership projects seeking to win mutually beneficial public or private contracts to advance the state of maritime hydrogen uptake in each port.
- Offshore collaboration: Projects specifically oriented to the offshore wind sector, expected to be an early adopter of maritime hydrogen.

ABP is in a privileged position to convene different stakeholders to collaborate both in the UK and overseas because of its size and influence. A proposed DfT UK Shipping Office for Reducing Emissions could provide an independent medium for UK collaboration.

4.5.3 Offshore Wind Sector

UK ports are well positioned to collaborate to develop zero emission SOVs, CTVs, export expertise, and fuel overseas as construction in the eastern North Sea continues to develop and floating offshore scales up.

Zero emissions fuelling for offshore wind O&M is very much in its infancy and, as such, new port ecosystems will need to be developed. This will involve not only the physical infrastructure required but also the training, standards and regulations involved in the novel use of technologies. It is important that these are harmonised across the sector to avoid market barriers due to incompatibility and reduce duplication of effort.

Opportunities for collaboration:

- Demonstrations of hydrogen bunkering for the UK offshore wind sector should be initiated alongside first movers Teesport, Aberdeen, Peterborough and Harwich which show promising potential. Green hydrogen production is expected to be large in Aberdeen.
- Continued collaboration with German O&M hub Emden.
- Liverpool and Vancouver are interested in collaboration for offshore wind hydrogen projects.
- The only potential competitor ports identified in the workshop were Port of Tyne and Teesport, which are seeking the same government support as ABP.
- Potential competition in future may arise with the ports surrounding Heligoland, a major offshore hydrogen production hub in the making.

4.5.4 Other Sectors

Norway is the leading country for hydrogen-powered vessels and bunkering in the NSR but it lacks production in scale. Ro-Ro Freight vessels could export of green liquefied hydrogen in tube trailers from Humber ABP ports. This would be a lucrative export market and would secure demand for Humber production.

Humber ports should pursue PTP collaboration with NSR ports to demonstrate a Clydebank Declaration Green Corridor route powered by green hydrogen. Short sea shipping General Cargo vessels would be most suitable for hydrogen power. Visits from Amsterdam, Antwerp, Bremen, Ruhr, Hamburg, Ijmuiden, Moerdijk, North Sea Port and Rotterdam are all candidates. More analysis of these visits must be undertaken to find PTP routes and suitable vessels. Car Carrier PTP visit between Cuxhaven and Grimsby carport also present an opportunity which requires further research.

5.0 REVIEW OF HYDROGEN-PROPELLED VESSEL PROJECTS

This section illustrates an overview of current ship projects that use hydrogen as a fuel and hydrogen technology in shipping. A review of over 60 hydrogen-related merchant ship projects was conducted which included seagoing ships as well as very small inland craft. For some of the projects identified, no published information of significance could be found and thus these projects have not been listed. Furthermore, publicly available research reports and feasibility studies have been reviewed as well. Naval vessels, such as partly hydrogen-powered submarines, as well as ships with fuel cells not using hydrogen as fuel, are not included in the review.

There are different ways that hydrogen technology is adopted on both inland and seagoing vessels, ranging from purpose-built newbuilds to retrofit of existing vessels. In some of the most recent and larger newbuild projects, the hydrogen-related components are scheduled to be retrofitted at a later point after delivery and entry into service of the ship. This might be due to time constraints, for instance the ship needs to enter into service but the time required for installing, testing and certifying the hydrogen equipment is longer. In such cases, the hydrogen components are not the primary source of power onboard and the equipment is usually located on deck, so that modifications to the ship are kept to a minimum.

A large portion of the projects involve vessels which derive partial power from hydrogen. A typical example is the double-ended Osterøy ferry Ole Bull where, of the two propulsors, one is diesel-powered and the other is to be converted to be hydrogen-powered (Prototech AS, year unknown). Another example is the Havila Kystruten cruise vessel where hydrogen provides emission-free operation when sailing in the Norwegian world heritage fjords (Havyard Group ASA, 2018). In the example of Fincantieri's ZEUS project, one of the project goals is to develop a new way of generating electricity and heat on board cruise ships (Fincantieri S.p.A., 2020). On Norled's liquid hydrogen Røgaland ferry, hydrogen fuel cells are present onboard along with battery and diesel power systems for redundancy, although in this case the ferry is capable of operating completely on hydrogen alone (Norled AS, 2019). Because the ferry route is an integral part of the national road system, is subject to high reliability standards required by the government. It is also interesting to note that the government required that at least 50% of the vessel's power needs are covered by clean hydrogen (Østvik, 2020).

The routes and operating areas of each vessel project reviewed, where known, were collected into Table 7 below. Where distances are known, they are given in nautical miles. It is evident that the majority of vessels operate in short routes or harbour areas.

Distance	**Route or operating area**	**Project and/or *vessel name***
Long	Worldwide, including polar navigation	MARANDA *Aranda*
	Worldwide, excluding polar navigation	Energy Observer, Race for Water
	Transatlantic	Lateral Engineering AQUA
	USA Coasts	Zero-V
Medium	Baltic Sea, unspecified location	Samskip SeaShuttle
	Norwegian West Coast	Havila Kystruten FreeCO2ast, HyShip Topeka
	Oslo–Frederikshaven–Copenhagen	DFDS Hydrogen Ferry
	Trondheim–Kristiansund, NO	Rødne E-Maran
	Rhine River, unspecified location	Future Proof Shipping Inland Vessel
	Hamburg–Berlin, DE, and other inland routes on rivers Havel, Spree and Elbe	*Elektra* Inland Pusher Tug
Short	Antwerp–Kruibeke, (4 nm), BE	Hydroville
	Alster River, Hamburg, DE	Alsterwasser
	Mittelplate Oil Field, Wadden Sea, DE	Coastal Liberty
	Rhine River, Bonn Area, DE	Hydra
	Nantes, FR	Navibus Jules Verne 2
	Rhône River, Lyon area, FR	Flagships Pusher Tug
	Kawasaki Port, JP	e5 Tug
	Yokohama Port, JP	e5 Tug, Yokohama Tourist Ship
	Amsterdam, NL	Nemo H2 Inland Tourist Boat
	Amsterdam–IJmouden, NL	H2Ships Tourist Boat *Havenbeheer*
	Delfzijl–Rotterdam, NL	FELMAR *Antoine*
	Finnøy-Route: Fogn–Judaberg–Nedstrand–Jelsa, NO	Norled Finnøy H2 Ferry Conversion *Hidle*
	Hjelmeland–Ombo Skibaviga–Nesvik–Hjelmeland (7 nm), NO	Norled Rogaland Liquid H2 Ferry *Hydra*
	Valestrand–Breistein (1.5 nm), NO	Osterøy *Ole Bull*
	Kirkwall–Shapinsay (4 nm), UK	HySeas III
	Bristol, UK	Passenger Ferry *Hydrogenesis*
	UK canals	Narrowboat *Ross Barlow*
	San Francisco Bay, USA	Duffy-Herreshoff DH30 Water Taxi, Water-Go-Round
	Harbour service, unspecified location	OSD IMT H2 Harbour Tug

Table 7 – Routes and operating areas of hydrogen-powered ships in the projects reviewed

Table 8 breaks down the projects reviewed by ship type. As mentioned above, projects where detailed information was lacking have not been included here.

Ship type	**Count**	**Ship type**	**Count**
Inland Cargo Vessels	5	Autonomous Underwater Vehicle	1
Inland Tourist Boats	5	Container Vessel	1
Passenger Ferries	5	Cruise Vessel	1
Research Vessels	5	Inland Passenger Ferry	1
Double-Ended Passenger and Car Ferries	4	Jack-up Vessel	1
Passenger Fast Ferries	4	Narrowboat	1
Crew Transfer Vessels (CTVs)	3	Offshore Construction Vessel	1
Harbour Tugs	3	Offshore Supply Vessel	1
Inland Pusher Tugs	2	Pleasure Yacht	1
Passenger and Car Ferries	2	Pure Car Carrier	1
Tourist Boats	2	Ro-Ro Cargo Vessel	1
Water-taxies	2		
Total individual ships	**53**		
Ferries, all types and sizes	**16**		
Tourist boats, all operating areas	**7**		

Table 8 – Number of hydrogen-powered ships by type in the projects reviewed

Consolidating all types of ferries and tourist boats into two categories, 16 Ferries and 7 Tourist Boats are counted. Thus, short-route ferries operating in national waters are the most represented hydrogen-powered ship type of all. There are several reasons that make such ferries suitable for hydrogen use, described below:

- **Short, predictable routes:** Most of these ferries operate on routes that are usually less than 10 nautical miles long and often in protected waters such as natural bays or fjords. The influence of heavy weather is smaller than on open sea routes and thus the energy requirement can be determined with a high degree of accuracy.

- **Storage space:** Due to safety regulations no passenger spaces are permitted below the waterline and in the case of car ferries, they are usually too short to make lower holds for vehicles practical due to the length needed for ramps. Thus, aside from machinery spaces, tanks and some service spaces, the hull below the main deck on most short-route ferries consists partially of unused void spaces. In case it is chosen to fit hydrogen storage below deck, the volume required is available and it is unlikely that the vessel would need to be built larger in order to accommodate hydrogen storage.

- **Low energy requirements:** The service speeds of short-route ferries are in the range of about 10 knots and the vessels make frequent stops. Thus, the operation is not continuous throughout the day as opposed to ships that sail distances requiring several days of uninterrupted navigation. The short routes allow for more frequent bunkering, even daily if needed, since the vessels commute between the same ports multiple times a day. The final storage capacity for hydrogen can be trimmed to the energy requirement, onboard space for storage and the desired bunkering interval. Necessary fuel reserves can be much smaller than for vessels operating on longer routes and on open sea.

- **Regulation:** Ferries operating in national waters are regulated by national regulations and not subject to international regulation. For a single flag state, it is easier to bring into force new regulation or case-by-case approvals that adapt to emerging technology, as opposed to the rather lengthy process of international maritime regulation. The Norwegian flag, in cooperation with DNV GL as provider of classification services, has a track record of introducing novel propulsion technology on ferries, with the first LNG-powered ferry *Glutra* in 2000 and the first battery-electric ferry *Ampère* in 2014. Another consideration for vessels engaged in international voyages is that port states might establish regulations of their own regarding onboard hydrogen use, which are beyond the control of the shipowner/operator.

Of course, it is possible to power other types of ships with hydrogen, provided the design is adapted to accommodate for it (or retrofitted). If current ship designs are to be changed as little as possible, then ships with certain characteristics can be considered to be more suitable than others. The following section explores how space onboard influences whether design changes are necessary to convert to hydrogen.

6.0 VESSEL TECHNOLOGY REVIEW

6.1 Onboard Hydrogen Storage

As introduced in Section 5, storing hydrogen onboard in sufficient quantities is one requirement of realising hydrogen power and propulsion on ships. This section describes the various available onboard hydrogen storage technologies, the two most widely adopted being compressed gaseous hydrogen in pressurized tanks and liquified hydrogen in tanks at cryogenic temperatures. Metal hydrides have successfully been employed on some of the earliest hydrogen powered boats around the early 2000s and on naval submarines for storing hydrogen. However, this technology has not been adopted in recent years for merchant projects, probably due to the progress of composite compressed hydrogen tanks. However, Fincantieri's ZEUS project is an exception, for which this storage method has been announced (Fincantieri S.p.A, 2020). Sodium borohydride is also briefly introduced in Section 6.1.3.

Another storage technology worth mentioning but not explored in detail in this report is LOHC. Numerous companies developing and producing LOHC fluids and related hydration/dehydration equipment are emerging. Other hydrogen storage technologies exist, some of which are actively being researched, but have not found their way into the maritime industry and are thus not expanded upon in this report.

Compared to compressed hydrogen storage at 350 bar, liquefied storage roughly doubles the volumetric energy density, taken as the ratio of a bounding box surrounding the respective tank and the energy content of the stored hydrogen therein. There are many factors that influence the choice between compressed and liquefied hydrogen storage onboard. Among the most important are:

- Quantity of hydrogen to be stored, mainly as a function of installed power (propulsion and/or auxiliary), load profile, sailing distance and operational/safety reserves;
- Available volume or deck area for installing tanks;
- Bunkering intervals, infrastructure and available time for bunkering operations;
- Economic considerations regarding the cost of gaseous or liquified hydrogen as well as the cost of infrastructure and related maintenance.

There is no simple answer to the question of which of the two technologies is more suitable for which application, as the choice depends on many factors. Nevertheless, an attempt is made at finding a basic indicator.

The first parameter chosen to be considered is the Total Stored Energy (*E*), which amalgamates the installed power, load profile, sailing distance, operational reserves and bunkering intervals, which can occur in any proportion to each other. For instance, a small vessel sailing great distances might require the same amount of stored energy as a larger vessel sailing short distances. This parameter is ultimately the basis for the space requirement for hydrogen storage onboard, regardless of vessel type, operation and size.

The second parameter chosen as a first approximation is the Gross Tonnage (*GT*) of the vessel as indicator of the vessel size and indirectly onboard space. A probably more meaningful formulation would be the Gross

Tonnage with the Net Tonnage (*NT*) subtracted, reminding that the Net Tonnage is a measure of the onboard space used for payload, either as cargo, passenger spaces or both. Therefore, this relation represents the vessel's total enclosed volume not intended to be used for payload. As an indicator, the Coefficient of Energy Storage (C_{ES}) is proposed and expressed by the following ratio:

$$C_{ES} = \frac{E}{GT} \quad (1)$$

or

$$C_{ES} = \frac{E}{GT - NT} \quad (2)$$

where *E* can be expressed in any appropriate unit for energy such as kWh, MWh or as the mass of stored hydrogen in kg or tonnes. For vessels for which tonnage measurement is not applicable, like for boats or inland watercraft, this formula is not applicable and another approach is needed. As an alternative to Gross Tonnage, the Length Overall (L_{OA}) could be used as a simple first approximation:

$$C_{ES} = \frac{E}{L_{OA}} \quad (3)$$

These proposed formulae allow comparisons between different types of ship, as the parameters shown are universally found among ship types. This method could be further refined and use a more elaborate method to quantify size or instead any arbitrary quantity that is characteristic of size for a particular ship type, like deadweight, displacement, deck area, lane metres, Twenty-foot Equivalent Units (TEU) and so on. However, such an investigation is outside of the scope of this study. Tonnage information was found for only a few of the reviewed projects, so C_{ES} based on L_{OA} is shown in Figure 20 for projects where this information is available. For considerations about spaces suitable for installing hydrogen storage, see Section 6.1.4.

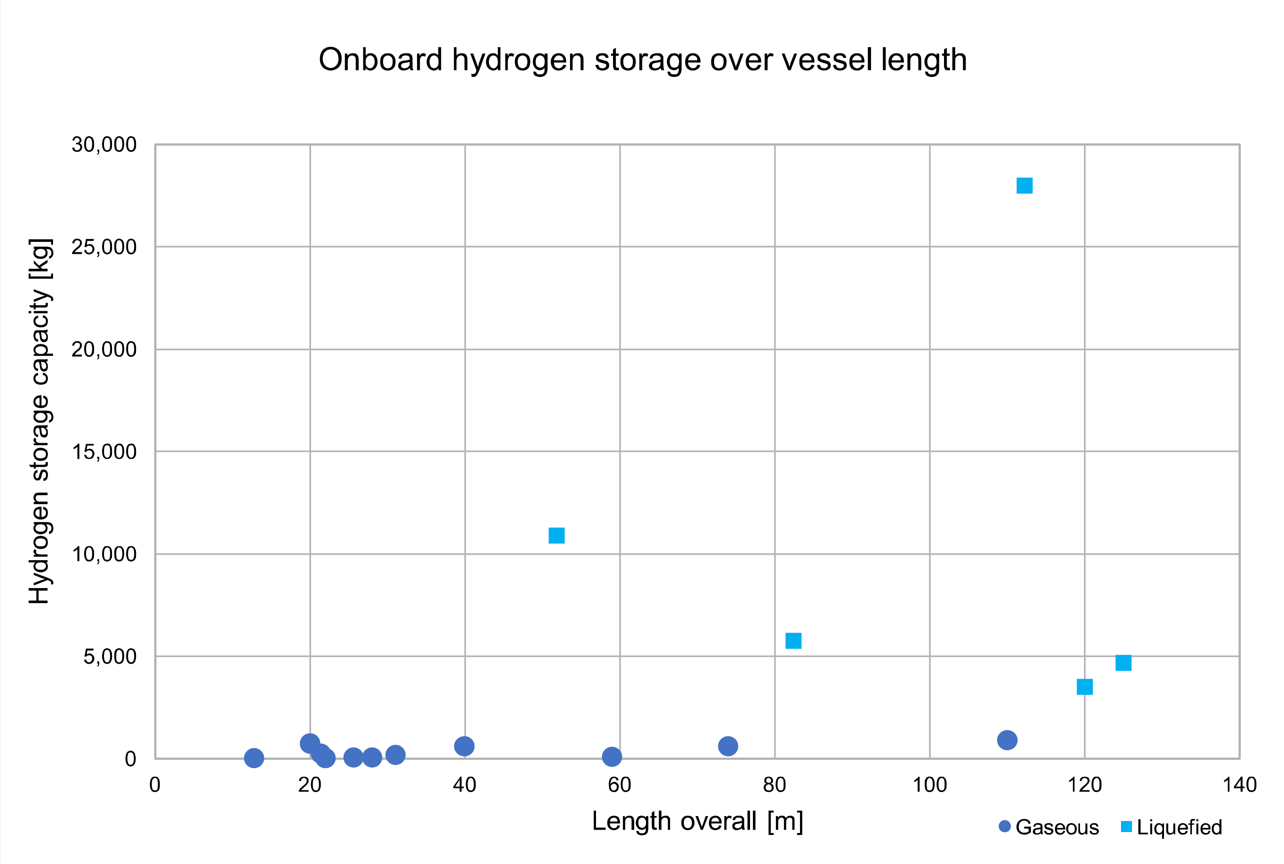

Figure 20 – Graph of Total Stored Energy, *E*, over Length Overall, L_{OA}, for hydrogen vessel projects reviewed

6.1.1 Compressed Gaseous Hydrogen

Storing compressed gaseous hydrogen in pressurized tanks can be considered a mature technology. Metal gas cylinders have existed for a long time but their heavy weight required to withstand meaningful pressures has limited their use in mobile applications. The higher the storage pressure, the more hydrogen can be stored within the same volume. At the same time, increasing the storage pressure requires a stronger and thus heavier tank. Development in the past decades has hence focused on building tanks that use stronger and lighter materials and at the same time prevent intra-molecular leakage of hydrogen out of the tank.

Generations of tanks used for compressed hydrogen are subdivided into the following types:

- **Type I**: Steel/aluminium gas cylinders similar to those for any technical gas, with storage pressure 250-300 bar;
- **Type II**: Aluminium cylinders with filament windings as reinforcement wrapped around them. The fibres can be made of glass, carbon or aramid. Storage pressure 250-300 bar;
- **Type III:** Composite tanks made of fibre-reinforced polymers with an inner metal liner. Storage pressure up to 700 bar;

- **Type IV**: Composite tanks made of fibre-reinforced polymers with an inner polymer liner. Storage pressure up to 700 bar.

The more advanced the type, the lighter the tanks are in comparison to the hydrogen fill that they can hold. In the reviewed ship projects, the specific type of tank is rarely indicated and the storage pressure is more easily found. The storage pressures found range from 200 to 500 bar. Composite tanks are sensitive to external mechanical damage. Abrasion, cuts or fractures of the exterior fibre windings may compromise the tank's pressure strength. Manufacturers can provide guidelines if such damage is safe to be repaired and how. From one manufacturer's user manual it can be taken that tanks might have an expiry date after which they should not be filled anymore and should be replaced. It is unclear whether this applies only to certain types of tanks and whether this is the case with other manufacturers as well.

Compressed hydrogen tanks can be installed both above or below deck and can be arranged in racks or even containers. In case of installation on deck, care should be taken to protect the tanks from being damaged, for example during cargo operations. Global Energy Ventures Ltd has patented a method to integrate compressed hydrogen gas storage into a ship hull and use it as a hydrogen tanker (Maritime Executive, 2020).

Compressed hydrogen tanks for use on ships were found in capacities up to 1500 L, corresponding to close to 28 kg of hydrogen capacity. A tank can only be emptied until the tank and withdrawal system pressures are equal, so the actual withdrawal quantity is lower than the tank capacity. Refilling compressed hydrogen tanks requires special high-pressure compressors to fill the tanks to their nominal storage pressure. As the pressure in the tank is built up, heat is released. In order to prevent the tank from overheating, the speed at which a tank can be filled is limited. This might represent a practical limitation when large quantities of compressed hydrogen need to be bunkered and there are time constraints on the bunkering process. Some projects envision swapping racks of empty hydrogen tanks with filled ones. The empty ones are then brought to an appropriate facility for refilling.

To date, the hydrogen ship project envisioning the largest known compressed hydrogen storage to be used as fuel is the DFDS hydrogen passenger & car ferry project, with a capacity of 44 t of compressed hydrogen (DFDS A/S, 2020). This is much larger than any other compressed hydrogen gas storage installation found on ships. The bunkering interval is given as 48 h or every round trip but details about the system are not disclosed.

6.1.2 Liquefied Hydrogen

Liquefaction of gases is used for many industrial gases like oxygen, nitrogen or helium. To improve its volumetric energy density, hydrogen can be liquefied by cooling it down to just below its boiling temperature at -253°C. At this temperature, pressurisation is not necessary in order to maintain the liquid state. Liquefaction is done at a specialized plant and is a very energy intensive process. The equivalent of up to 30% of the hydrogen's energy content is required for its liquefaction. For comparison, compression of hydrogen gas to a storage pressure of 350 bar, typically requires approximately 6% of the hydrogen's energy content, whereas for a pressure of 700 bar this becomes 11%. Due to the extremely low temperature required, all components in contact with liquified hydrogen need to be thermally insulated to avoid absorption of heat from the environment and they need to be made of materials suitable to such low temperatures without degradation or structural failure.

Tanks for liquefied hydrogen are very similar in design to other tanks for liquefied gases or LNG tanks used on ships, the main difference being the much lower storage temperature and material compatibility with hydrogen. They are cylindrical in form and consist of an inner tank storing the liquid and an outer enclosure. The space in between is usually a vacuum, filled with low thermal conductivity materials such as perlite. Any connection pipes pierce the outer enclosure through to the outside. For hydrogen use, highest demands are placed on the insulation because in comparison to other liquefied gases, the storage temperature is even lower. Although the tanks don't need to be pressurized in principle, they are designed as pressure vessels to withstand pressures of 5-10 bar.

Despite careful insulation, the tank slowly absorbs heat from its environment and part of the liquid inside evaporates, it boils off. Evaporating gas increases the pressure inside the tank, which should be kept within safe limits. If hydrogen is not withdrawn from the tank, built up boil-off gas needs to be safely evacuated to the environment to maintain a safe pressure. This process can also be used in a controlled way to withdraw hydrogen from the tank at relatively low flow rates without the need for a pump. The boil-off rate is a characteristic of tanks for liquefied gases and for hydrogen it is in the order of up to 1-2% per day for typical industrial tanks, but depends largely on the ratio between volume and surface area. From this point of view, spherical tanks offer the least exposed surface area and such tanks are found on LNG tankers or for large-scale industrial storage. However, they are more difficult to manufacture.

In order to keep the inner tank cool, a portion of the content should always be kept inside, therefore the withdrawal quantity is lower than the tank capacity. Due to the boil-off losses, liquefied storage is better suited to installations with rather continuous withdrawal than longer term storage with less frequent withdrawal. Tanks for liquefied hydrogen are manufactured in sizes up to approximately 600 m^3, corresponding to roughly 42 tonnes of liquid hydrogen. The first ferry using liquefied hydrogen is currently under construction.

Pipes for transport of liquid hydrogen are double-walled vacuum-insulated pipes. Special cryogenic pumps exist for moving liquid hydrogen in large quantities and these are manufactured by specialized companies. Any other type of fitting (like shut-off valves etc.) needs to be of cryogenic type and suitable for liquid hydrogen use. Before hydrogen can be supplied to fuel cells or engines, it needs to be brought to gaseous state by means of a vaporizer. This is explained further in Section 6.1.2.

There are a few ship projects of liquefied hydrogen tankers, the first of which, the *Suiso Frontier*, was launched in late 2020 (Kawasaki Heavy Industries Ltd., 2020). Although these ships are going to use conventional propulsion without hydrogen, they are interesting nevertheless because they are a shipboard application of large volume liquefied hydrogen storage. The *Suiso Frontier* has a cargo tank capacity of 1250 m^3 of liquefied hydrogen, corresponding to approx. 90 tonnes. Kawasaki Heavy Industries, its builder, has announced plans for a much larger tanker with 160,000 m^3 capacity (Kawasaki Heavy Industries Ltd., 2015).

6.1.3 Sodium Borohydride

Sodium borohydride ($NaBH_4$), a granular solid substance, can be used as a hydrogen carrier. In an aqueous borohydride solution and by means of a catalyst it releases hydrogen, heat and the reaction by-product sodium metaborate ($NaBO_2$). This method is chosen as a means of storing hydrogen for the Port of Amsterdam H2Ships project, an inland tourist boat (NWE Secretariat, 2019). The process of regenerating the spent reaction by-product back to sodium borohydride is currently being researched. The regeneration process is envisioned to take place ashore and not on the boat. This technology requires less volume than storing the hydrogen in compressed gaseous form (Egbertsen, 2020).

6.1.4 Space for Hydrogen Storage

Regardless of whether hydrogen is stored in compressed or liquified form, its energy density is a fraction of that of conventional fuel oils. Although the efficiencies of fuel conversion for fuel oil and hydrogen need to be considered, the order of magnitude of the required chemical energy for a given ship is the same for both. Because fuel oil is a space-efficient means of storing energy, it can be safely assumed for many ships that there is more fuel oil capacity present than really necessary to guarantee a certain operating range. This may be for various reasons, such as the excess capacity is needed for maintaining adequate stability and is replaced by water ballast as it is consumed. Another possible reason, especially for deep sea vessels, is that the capacity is not necessarily dimensioned to be able to bunker between the ports that are furthest away for the intended trade, but rather to extend the bunkering interval so that fuel oil can be bunkered in ports that offer fuel oil at a convenient price. This assumes that the cost of carrying extra fuel is offset by the ability to bunker it where it is cheap. Considering this and depending on the particular ship, it may or may not be necessary to carry the same amount of chemical energy when using hydrogen. Since hydrogen takes up more space onboard in comparison to fuel oil, the priority obviously lies on satisfying operational requirements first. Therefore, the energy storage capacity might be reduced as a first measure, if for instance more frequent bunkering is possible and safe.

It is essential to assess available onboard space not only quantitatively but also qualitatively. Typical spaces on seagoing ships used for storing fuel oil are double bottoms, double sides and deep tanks, which all form part of the ship's hull structure. Since fuel oil is a pumpable liquid at room temperature (or heated if heavy oil) and does not require to be pressurized, its tanks can have virtually any shape and the presence of structural members is of no consequence. When structural inspections are due, fuel oil tanks can be emptied, cleaned, ventilated and accessed to be inspected. They provide a very efficient use of volume, especially those that are too confined to be used for cargo.

This is different for hydrogen storage, where the tanks are independent and separated from the hull structure (except possibly if hydrogen carrier fluids are used). If spaces below deck are to be used to accommodate hydrogen tanks, some restrictions apply as to their installation location. Although there is no current specific international regulation for hydrogen as fuel onboard ships, for the time being the International Code of Safety for Ships using Gases or other Low-flashpoint Fuels, or IGF Code, is often used for guidance.

The IGF Code states that boundaries of tanks carrying liquified gas should have a certain minimum distance from the outer shell, as a measure to prevent tank damage following a collision. If those distances to the bottom and the sides are deemed to be too large, they can be reduced to some extent by calculating the probability that the compartment containing the tank will be damaged. Nevertheless, a minimum distance of at least 0.8 to 2.0 m (depending on ship dimensions) has to be kept in any case. If this rule is applied to hydrogen, this excludes spaces traditionally used for storing fuel oil from being used for hydrogen storage. Furthermore, larger tanks, which are typically elongated cylinders with at least a few metres diameter, are too large to fit within confined structures such as double bottoms or double sides with closely-spaced structural members.

This means that large capacity tanks fitted below deck can only be installed detached from the outer shell, in areas normally used by cargo holds. National regulations or those for small craft may depart from this fuel tank protection, but it can be expected that if hydrogen regulations are developed for large seagoing vessels, they will likely build upon existing regulations for LNG installations. There may be further restrictions on the location of below-deck hydrogen tanks, such as the presence of nearby fire hazards like machinery spaces, that would need to be carefully considered.

Vessels that are designed with large void spaces below deck have an advantage for fitting hydrogen storage over vessels where these spaces are all occupied. Typical vessels that may fall within this category are:

- **Short-route ferries:** As explained in Section 5.
- **Large passenger and vehicle ferries:** Like short-route ferries, these vessels are not allowed to have passenger spaces below the main deck, thus possibly having unused spaces available. Where a lower hold for vehicles is present, it does not extend to the sides but has longitudinal bulkheads set in from the sides, due to damage stability regulations to protect the lower hold from flooding. The lateral spaces typically form tanks, void spaces or contain machinery. In contrast, cargo ferries that do not carry passengers, and thus for which these onerous damage stability regulations do not apply, have the lower hold typically extending fully to the sides.
- **Offshore construction vessels:** These ships usually have the superstructure and machinery spaces located forward and rely on the aft deck area as their principal payload facility. If no stores or cargo spaces for construction equipment or material are present below the aft deck, these spaces may be for the most part empty.
- **Deadweight carriers:** This is a general term referring to ships designed to carry heavy cargo (cargo with rather large densities such as aggregates or mineral ores). The opposite are volume carriers, which comprise the majority of ships. Deadweight carriers typically have cargo holds that are narrower than the hull and the lateral spaces are void and provide buoyancy. Typical deadweight carriers are ore carriers and dredgers.
- **Harbour tugs:** Some harbour tug designs have unused space below deck, e.g., beneath the aft deck between the engine room and the aft peak.

This list is by no means complete and although ships can be categorized in types, there are always exceptions as ships can have very diverse and customized designs. In essence, every ship that has unused spaces below deck is more likely to be able to transition to hydrogen fuel as opposed to vessels where their size would have to be increased to accommodate hydrogen storage.

Hydrogen tanks may also be fitted on deck, if sufficient area is available. In this case, the wind profile would need to be considered as well as transverse stability. Tanks that are detachable would be considered as cargo and not add to the vessel's Gross Tonnage, whereas tanks attached permanently would add thereto. The area immediately surrounding the tanks is likely to be a hazardous area and needs to be included in the deck area requirement. Particular care should be given to deck-mounted tanks in case of deck cargo operations, to protect the tanks from accidental damage.

6.2 Bunkering

Very little information is found on the topic of bunkering among the reviewed projects. Bunkering methods include refuelling stations, replacement of compressed hydrogen gas tank racks or containers with full ones and refuelling of liquified hydrogen by truck. Road transport might require certification of the storage unit to be fit for road transport, which might increase the certification onus (VTT, 2018).

For the Havila Kystruten passenger ship project, the authorities have demanded that no passengers are to be onboard during hydrogen bunkering (Valland, 2020). The H2Ships project using sodium borohydride as a hydrogen carrier is to mix it with water to make a pumpable solution. An onboard catalyser extracts the hydrogen to supply the fuel cell. The spent solution is then hydrated again. The production method of the hydrogen to be used is indicated only for the minority of projects. Most notably, the *Ocean Observer* and *Race for Water* generate their hydrogen from seawater as a means of storing energy generated onboard from solar power or hydrogeneration (Energy Observer SAS, 2017; Race for Water Foundation, year unknown). Hydrogeneration means using the ship's propeller as a turbine and its connected electric motor as a generator to convert wind thrust to electricity.

6.3 Propulsion

If hydrogen fuel cells are used for power generation, propulsion is always electric; the fuel cells generate electricity and the propulsors are driven by electric motors. In these configurations the fuel cells are always complemented by electric batteries as well. The function of the batteries is to provide power when the fuel cells are not operating, to absorb short-term power peaks and thus avoiding installation of additional fuel cells (so-called "peak-shaving") and to supply power during transient loads.

Where hydrogen-fuelled engines are used, propulsion can either be mechanical using the engines as prime movers or like in a diesel-electric configuration, the engines can drive electric generators which supply an electric propulsion system.

6.3.1 Fuel Cells

PEM fuel cells are a maturing technology and are now finding their way into the maritime industry. Of the reviewed projects, where the type of fuel cell used is indicated, it is always the PEM type. Solid oxide fuel cells (SOFC), which are expected to reach higher conversion efficiencies, are still under development or are used in combination with fuels other than hydrogen.

There are currently at least eight manufacturers of PEM fuel cells that are producing commercially available marine PEM fuel cells or have announced to do so. The currently available module outputs range from 0.5 to 1,200 kW. The recently announced hydrogen ferry project by DFDS envisions a total installed fuel cell power of 23 MW, with entry into service planned in 2027 (DFDS A/S, 2020). Manufacturer PowerCell is working on projects with installed hydrogen fuel cell powers of 3 MW expected to be operational by 2022 and 24 MW by 2025. Nedstack, another fuel cell manufacturer, reports that its fuel cell modules of 500 kW can be scaled up to 6 MW systems with a high level of redundancy by connecting them in parallel. With larger module sizes, even larger outputs would be achievable.

The installed fuel cell power of the projects reviewed is plotted in Figure 21, with at least one multi-MW vessel already under construction. Nedstack expects that over the next couple of years, R&D will cause an increase in the power density of fuel cells, allowing greater module sizes and at the same time reducing their cost. These improvements are expected to be most effective when based on operational experience of today's technology on ships and it is thus key to keep investing and realizing marine applications. It can therefore be expected that within the next decade, hydrogen fuel cell installations will reach power outputs of tens of MW, in the same order of magnitude as currently available marine diesel engines and gas turbines.

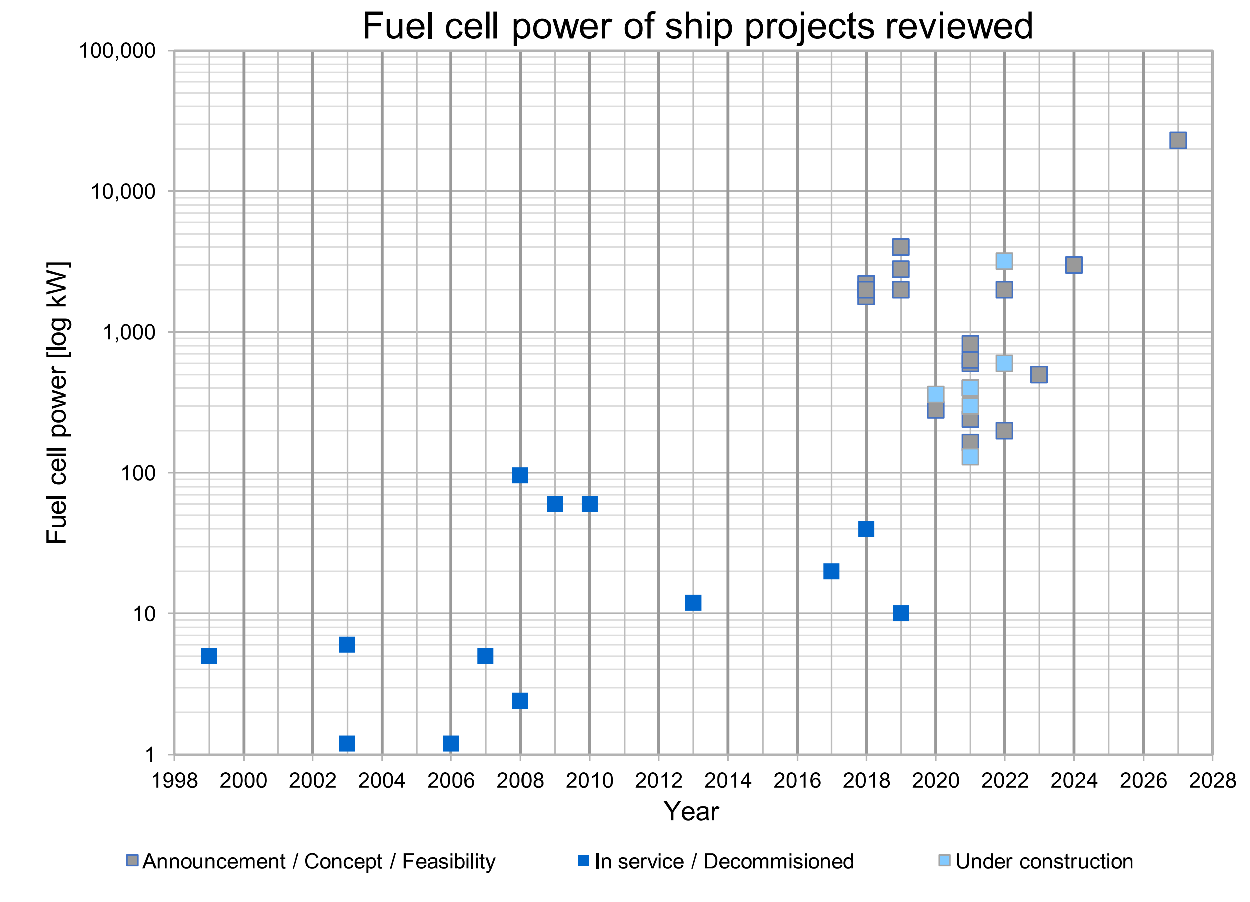

Figure 21 – Graph of total installed hydrogen fuel cell power (in logarithmic scale) of individual ship projects over years

The maximum reported PEM efficiency is 58% and averages at around 50% among the various modules on the market, typically occurring at part load. Although this conversion efficiency is somewhat higher than for most diesel engines, losses are incurred in the necessary power converters and other components of the electric propulsion plant. On the other hand, diesel-mechanical propulsion incurs less losses on the shaft line. If compared to diesel-electric ships, the fuel to propeller efficiency of a fuel cell system can be expected to be slightly better due to more efficient fuel cell in comparison to engines coupled to generators. If compared to diesel-mechanical propulsion it is roughly equal because the better fuel cell efficiency is contrasted by the higher losses in the electric propulsion components not present in a diesel-mechanical plant. Nevertheless, in case of vessels often operating at part loads, electric propulsion with several diesel generating sets or multiple fuel cells can result in being more efficient despite the electric losses. PEM fuel cells may need up to 30 seconds from standby to reach nominal output. In case of high transient loads, such as dynamic positioning, these can be absorbed more quickly by electric batteries connected to the power grid (Glosten, 2018).

The more advanced modules are offered enclosed within leak-proof cabinets containing all the balance of plant components. PEM fuel cells produce direct current (DC) power with varying voltage depending on the load. To integrate them into the onboard power grid which has constant voltage, they therefore need either a

DC/DC or DC/AC converter, depending on the bus type they feed into. A power converter is a device that converts a variable input voltage and current to a constant voltage output with variable current. The maximum output voltages of different fuel cell models range from a few hundred up to 1,200 V DC. Some manufacturers indicate 20 years life expectancy for the module and between 10,000 up to 34,000 hours for the stacks. Where a cooling method is indicated, all modules use liquid cooling. PEM fuel cells are very sensitive to hydrogen impurities and require high levels of purity to prevent membrane degradation. The highest required purity found is indicated to be 99.99% which corresponds to the ISO 14687 Grade D or SAE J2719 Grade 4 standards. However, only a few manufacturers include this information in data sheets.

PEM fuel cells are always supplied with gaseous hydrogen. When compressed hydrogen storage is used, other than shut-off valves, pressure and flow regulators, no other particular equipment is needed on the supply side. The storage pressure needs to be reduced to the supply pressure, which for fuel cells is typically in the order of a few bar. If liquefied hydrogen is used, an additional device called vaporiser is needed, which makes the hydrogen evaporate and warms it to a temperature compatible with the fuel cell. The vaporiser's capacity needs to be matched to the required supply flow rate. Compressed hydrogen systems are therefore simpler to implement than liquefied ones.

PEM fuel cell modules can be scaled in output by connecting them in parallel. When multi-megawatt outputs are required, the output voltage becomes a limiting factor. In order to limit short circuit currents and ohmic losses in cables, main power distribution voltages of 6 or 11 kV are commonly found on larger ships with electric propulsion. No specific information was found on the envisioned operating voltages and integration into the power grid in such high-power plants. Another potential issue related to up-scaling is the fact that given current module sizes, multi-megawatt installations may require tens or even hundreds of modules, depending on total power and single module output. Considering that currently the modules are enclosed in cabinets with doors for maintenance, similar in size as those for switchboards, they need to be arranged to be accessible and additional deck area for access corridors needs to be provided. In such high numbers they might become somewhat inefficient in terms of footprint area. On the other hand, for certain applications the possibility to decentralise comparatively small modules throughout the ship might prove beneficial and very high levels of redundancy are possible. Both on-deck and below-deck installation of fuel cell modules was found in the reviewed projects. Installations on deck are realised in enclosed cabinets or as containerized solutions. The advantage of an installation on the open deck is the natural ventilation and reduced risk associated with hydrogen leakage and fire hazard. An installation below deck in enclosed spaces requires more onerous ventilation, leak detection, alarm and fire prevention measures.

When fuel cells are chosen to convert the hydrogen fuel to electrical power, ship types with electric propulsion have the advantage that most electric equipment remains the same, roughly from the main switchboard downstream to the propulsion motors. The only difference would be that the diesel engines with all their auxiliary equipment and generators would be replaced by fuel cells and power converters. If, on the other hand, a ship which typically uses diesel-mechanical propulsion is to use hydrogen fuel cells, then the additional cost of the electric propulsion plant is added. Offshore service vessels, cruise ships, short-route ferries and research vessels are examples of ships often equipped with diesel-electric propulsion.

6.3.2 Hydrogen-fuelled Engines

Anglo Belgian Corporation has successfully developed ICEs capable of burning hydrogen using diesel as pilot fuel for ignition. Presently, this technology is being scaled up for engines in the 2-3 MW range with the engines burning up to 85% hydrogen and 15% diesel fuel (Anglo Belgian Corporation nv, 2020). Despite using hydrogen, this is not an emission-free technology. Since the hydrogen is combusted, the engine is impurity tolerant as opposed to the high hydrogen purity required by PEM fuel cells to prevent membrane degradation. Therefore, SMR from natural gas, so-called 'grey hydrogen', can be directly used. Engine manufacturer Wärtsilä has announced development of hydrogen-fuelled engines in 2020 (Wärtsilä Corporation, 2020).

NO_x is still formed during the combustion process, because their formation is inherent to reciprocating engines. They occur at high pressures and temperatures and are only indirectly dependent on the type of fuel used. The type of fuel and the specific combustion process determines whether the Otto or Diesel cycle is used, where the latter is more prone to NO_x formation due to generally higher working pressures. NO_x emissions are regulated and if necessary, they need to be mitigated either by engine-internal measures of the combustion process or by exhaust gas aftertreatment (such as scrubbers).

If fuel oil is used as pilot fuel to ignite the hydrogen, any emissions typical for that type of fuel are likely to occur, including CO_2, NO_x, SO_x and PM. Despite the theoretical possibility of combusting hydrogen alone without mixing other fuels, the exhaust gases would still contain residuals of combusted lubricating oil, albeit in small quantities, which is found in any type of reciprocating engine, regardless of the fuel used. Therefore, even though the polluting emissions to the atmosphere are drastically reduced with hydrogen-fuelled engines, in order to eliminate them completely, they would need to be removed from the exhaust gases in some way.

6.3.3 Hydrogen-fuelled Gas Turbines

Although no ship project using hydrogen-fuelled gas turbines was found, they might at some point play a role in some very specific applications, like large fast ferries or other applications where power density is critical. Gas turbines partially fuelled with hydrogen mixtures exist and burning pure hydrogen is being researched (Access Intelligence LLC, 2019).

6.4 Technology Readiness Levels

Table 9 shows an overview of the main components of hydrogen plants aboard ships and their TRLs, based on the review of current technology. For merchant ship applications, oftentimes new technology moves from workshop or drydock testing directly to commercial application, because operating a ship without commercial activity (paying cargo or passengers) for the sole purpose of testing a technology, is highly improbable due to financial constraints.

Technology	Gaseous storage	Liquefied storage	Gaseous bunkering	Liquefied bunkering	PEM fuel cells	SOFC	H_2 ICE
Readiness level	8-9	7	8-9	6-7	8-9	4	6

Table 9 – TRLs of marinized hydrogen systems

On land, gaseous hydrogen refuelling is widely used in hydrogen refuelling stations for cars and buses and is therefore at TRL 9. However, such a system has not been previously undertaken on a platform, so any conversion undertaken would be considered a pilot, at TRL 5.

Although the maritime industry possesses considerable knowledge of the transfer of cryogenic liquid fuels (namely LNG) to vessels (at TRL 9), this has not been undertaken with hydrogen or from a platform at sea. Thus, the first time this was undertaken would be considered a pilot with a TRL of 5.

7.0 SAFETY CONSIDERATIONS

Hydrogen is a relatively uncommon fuel within the maritime industry and therefore of key concern to players is its safety. However, on land, hydrogen is an industrial gas which is produced, transported and consumed in vast quantities all over the world – about 53 million tonnes per year[7]. Pipelines stretching hundreds of kilometres in length have transported hydrogen for decades in various countries[8]. Therefore, hydrogen as an industrial gas is well-understood by engineers and appropriate safety protocols have been developed and applied for its use. With the correct engineering, there is no reason for a hydrogen system to be inherently unsafe.

7.1 Safety Data

Rather than simply present data for the ignition and flammability of hydrogen, the data has been compared to natural gas, a known and understood fuel within the maritime industry. Both hydrogen (H_2) and natural gas (NG) will be explored in both their high-pressure gaseous forms and their liquefied forms (LH_2 and LNG).

The first key point is that hydrogen and natural gas themselves are not flammable. They are only flammable when mixed with oxygen (or another oxidant). Thus, hydrogen or natural gas in a sealed vessel is not flammable, but if it leaks into the environment and is exposed to oxygen, it will become flammable. The same is true for the liquefied form of the gases: For both LNG and LH_2, the cryogenic liquid itself is not flammable and neither is the gaseous hydrogen or natural gas that evaporates from their surface. Only when that evaporated gas mixes with air is it flammable.

In the event of a fuel escape, knowledge of where the flammable atmosphere is likely to form is required for the design of the surrounding environment and safety systems; specifically, extraction and detection systems. Hydrogen and natural gas at atmospheric pressure are both lighter than air (although hydrogen significantly more so), so will rise in the event of a leak due to buoyancy. However, if this leak is from a pressurised vessel, the gas will form a momentum driven cone-shaped jet which will travel in a straight line from the leak point and may reach several, or even tens of metres before the gas slows sufficiently for buoyancy effects to take over, allowing the gas to rise.

However, a leak from an LH_2 or LNG system will fall to the floor and form a puddle. From here the gas will evaporate but the gas is likely to be heavier than air due to its low temperature. It will therefore move along the ground, before eventually warming and rising.

Table 10 breaks down the properties of GH_2, LH_2, NG and LNG for comparison.

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[7] US Department of Energy, "The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Dioxide Emissions," Washington, 2008.

[8] Hydrogen properties, Releases and Dispersion, Hysafe, University of Ulster.

Property	**Gaseous Hydrogen (GH_2)**	**Liquefied Hydrogen (LH_2)**	**Gaseous Natural Gas (NG)**	**Liquefied Natural Gas (LNG)**
Storage temperature (°C)	Ambient	<-253[9]	Ambient	<-83[10]
Storage pressure (bar)	500 or 700*	<5[11]	~240[12]	<15[13]
Lower flammability limit (% in air)	4[14]	NA	4.4[15]	NA
Upper flammability limit (% in air)	74[16]	NA	16[17]	NA
Minimum ignition energy (µJ)	19[18]	NA	280[19]	NA
Density at atmospheric pressure (as a fraction of air)	0.0696[20]	NA	0.55[21]	NA

[9] Hydrogen Storage Basics, Department of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-storage-basics, Accessed 11/12/20

[10] All About LNG, CHIV, https://www.ch-iv.com/all-about-lng/, Accessed 11/12/20

[11] Private discussion with Chart Industries

[12] CNG Storage, PURE Energy Centre, https://pureenergycentre.com/cng-storage/, Accessed 11/12/20

[13] All About LNG, CHIV, https://www.ch-iv.com/all-about-lng/, Accessed 11/12/20

[14] Explosive Lessons in Hydrogen Safety, NASA, https://www.nasa.gov/pdf/513855main_ASK_41s_explosive.pdf, Accessed 11/12/20

[15] Explosive Concentration Limits, Engineering Toolbox, https://www.engineeringtoolbox.com/explosive-concentration-limits-d_423.html , Accessed 11/12/20

[16] Explosive Lessons in Hydrogen Safety, NASA, https://www.nasa.gov/pdf/513855main_ASK_41s_explosive.pdf, Accessed 11/12/20

[17] Explosive Concentration Limits, Engineering Toolbox, https://www.engineeringtoolbox.com/explosive-concentration-limits-d_423.html , Accessed 11/12/20

[18] Spontaneous Ignition of Hydrogen, Health and Safety Executive, https://www.hse.gov.uk/research/rrpdf/rr615.pdf, Accessed 11/12/20

[19] Electrostatic Hazards, Their Evaluation and Control, Haase, H. (1977), Verlag Chemie, Weinheim

[20] Hydrogen Properties, Office of Energy Efficiency and Renewable Energy, https://www1.eere.energy.gov/hydrogenandfuelcells/tech_validation/pdfs/fcm01r0.pdf, Accessed 21/12/20

[21] Methane - Density and Specific Weight, Engineering Toolbox, https://www.engineeringtoolbox.com/methane-density-specific-weight-temperature-pressure-d_2020.html, Accessed 21/12/20

Temp increase required for liquid release to become more buoyant than air (°C)[22]	NA	~2	NA	~53
Diffusivity (cm^2/s)[23]	0.756	NA	0.21	NA
Steady state vaporisation rates of liquid pools without burning ($cm\ min^{-1}$)[24]	NA	2.5-5	NA	0.05-0.5
Minimum auto-ignition temperature (°C)[25]	500	NA	580	NA
Upper Wobbe Index (kcal/Nm3)[26]	11,528	NA	12,735	NA
Flame Speed (cm/s)[27]	300	NA	30	NA

*These are the present standards for hydrogen fuelled land-based vehicles

Table 10 – Summary of the physical properties of hydrogen and natural gas

7.2 Discussion

All fuels are energy stores and if energy is released in an uncontrolled way from any fuel, it presents a danger. Therefore, when undertaking a safety comparison between two fuels, the differences in safety between the two fuels are marginal when compared to substances which do not contain enough energy to be considered fuels.

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[22] Comparison of the Safety-related Physical and Combustion Properties of Liquid Hydrogen and Liquid Natural Gas in the Context of the SF-BREEZE High-Speed Fuel-Cell Ferry, Sandia National Laboratories, .

[23] Air - Diffusion Coefficients of Gases in Excess of Air, Engineering Toolbox, https://www.engineeringtoolbox.com/air-diffusion-coefficient-gas-mixture-temperature-d_2010.html, Accessed 22/12/20

[24] I. Uehara,"Handling and Safety of Hydrogen," Energy Carriers and Conversion Systems, vol. I, 2013,

[25] Fuels and Chemicals - Autoignition Temperatures, Engineering Toolbox, https://www.engineeringtoolbox.com/fuels-ignition-temperatures-d_171.html, Accessed 22/12/20

[26] Fuel Gases and Wobbe Index, Engineering Toolbox, https://www.engineeringtoolbox.com/wobbe-index-d_421.html, Accessed 22/12/20

[27] Hydrogen: The Burning Question, The Chemical Engineer, 23/9/19

7.2.1 Comparing Gaseous Hydrogen and Natural Gas

GH_2 and NG are stored in high pressure vessels. As discussed, hydrogen is generally stored at either 350 or 700 bar, while Compressed Natural Gas (CNG) is usually stored below 250 bar[28]. Thus, there is an obvious benefit in storing at lower pressures or natural gas; however, in 'normal' operation, the vessels do not present a safety risk. This primarily comes from failure events leading to a leak scenario.

A leak will result in a high-pressure supersonic jet of gas, which eventually slows to a plume of gas which then dissipates. As hydrogen is stored at higher pressure, its jets are likely to extend further than natural gas. However, a jet is only a significant hazard if ignited, therefore a leak is only a hazard if there is an ignition source. It should be noted that all fuels must be stored in classified areas - i.e., with equipment which cannot cause ignition in the event of a leak. As such, a fuel leak should not result in an ignition, nevertheless as a worst-case scenario, this consequence will always be considered. Unignited fuel poses little risk (other than asphyxiation) as it can escape into the atmosphere.

The outcomes of ignition can be broadly split into:

- **The jet ignites soon after release**. Those in the direct line of the jet will suffer significant burns, equipment in the direct line will be damaged. As pressure vessels are often stored in banks, the ignited jet may impinge directly on another pressure vessel, which could lead to its localised softening and eventual failure (see below). The energy of the flame depends on its calorific value (significantly higher for methane) and the volume of gas that can escape the hole, which in turn depends on its viscosity (which is lower for hydrogen than NG). These effects are brought into a single metric, referred to as the Wobbe index (a measure of the interchangeability of fuel gases and their relative ability to transfer energy through a hole) and as shown in Table 10, these are broadly similar for hydrogen or natural gas, so in terms of energy release from a hole, they present a similar hazard.

As the release is localised and quickly ignites, gas detectors within the compartment are unlikely to have a beneficial effect. However, IR or ultrasonic detectors should be triggered and provide warning of a problem.

- **The jet ignites sometime after the release**. The area surrounding the leak has an explosive cloud of gas which on ignition, will lead to a deflagration and possible detonation (supersonic combustion) of the gas. Outdoors, hydrogen is safer due to its ability to diffuse away quicker and higher buoyancy, meaning less gas is available to ignite. However, in an enclosed area, such as a compartment on a ship, this will have little benefit. Here, methane is safer as hydrogen's higher flame speed means that hydrogen has a higher propensity for the flame deflagration to turn to

[28] Filling CNG Fuel Tanks, US Department of Energy, https://afdc.energy.gov/vehicles/natural_gas_filling_tanks.html#:~:text=Pressure%20rating%3A%20The%20typical%20industry,on%20a%2070%C2%BAF%20ambient%20temperature, Accessed 22/12/20

detonation, particularly in a 'cluttered' area[29]. Detonation of the gas releases considerably more energy, is more destructive and should be avoided.

In terms of mitigation, the gas and ultrasonic detectors in the compartment should provide early warning of the release before it is ignited.

7.2.2 A Pressure Vessel Failure

A vessel failure is a catastrophic event that will instantly release all the pressurised contents of the store. Given the energetic pieces of metal that will be projected at high velocity, it is likely that a spark will be present that will ignite the release (and therefore area classification has little benefit), leading to secondary explosions. Causes of this vessel failure could be corrosion of the cylinders (prevented by mandatory inspections), over pressurisation of the cylinders (prevented by pressure monitoring devices and pressure relief valves), general softening of the vessels due to a fire in the compartment (prevented by smoke and heat detectors) or localised softening of the cylinders caused by an ignited jet fire (prevented by IR and ultrasonic detectors).

In this situation, it could be considered that gaseous H_2 is more dangerous than NG as the tubes are stored at higher pressures, so the initial energy release would be higher. However, the energy released from decompressing the gas is an order of magnitude less than the energy of the fuel it contains and for the secondary ignition of the released gas, for a given tube size, natural gas has 3 times the calorific value so would release considerably more energy than an equivalent hydrogen tube. However, given the wider flammability limits, several times more of the hydrogen is likely to actually be ignited. Thus, while this is a highly undesirable event with either gas, the difference in the energy released between hydrogen and methane is minimal.

7.2.3 Comparing LH_2 and LNG

Under normal conditions, both LH_2 and LNG are stored in thermally insulated vessels at a low pressure (between atmospheric and 5 bar). Such storage presents a cryogenic hazard but the insulation on vessels and pipes will prevent direct contact with these low temperatures. The main hazards are thus associated with a loss of containment. However, all LH_2 and LNG installations are required to meet the relevant classification standards which are designed to all but eliminate the possibility of a leak and remove any chance of ignition. Indoors, gas detectors will identify the leak and the correct application of hazardous area zoning and spatial design should prevent an ignition and detonation. However, in the rare event of an indoor ignition, for a given leak rate, the higher heat capacity of methane means that more energy will be released with an LNG leak but the wider flammability limits will mean that the energy released will be similar with hydrogen. However, if the hydrogen deflagration turns to detonation, then this will release considerably more energy.

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[29] Explosion Hazards of Hydrogen-Air Mixtures, HySafe,

Examining two specific scenarios:

- A minor leak of liquefied fuel (dripping, or trickle) will present a minimal cryogenic hazard to staff as it will evaporate on contact with clothing or skin. The hazard is thus that it will rapidly evaporate, releasing a plume of flammable gas. Eventually, the puddle size will have an evaporation rate which will match the leak rate. In theory, hydrogen will evaporate faster due to its higher evaporation rates and lower boiling point, but in practice both will take seconds to become a hazard. Outdoors, this flammable gas will rapidly dissipate and present minimal hazard.
- A major leak of liquefied fuel could be caused by pipe failure due, for example, to an external impact. For a large release, evaporation will not be quick enough to prevent a significant pool forming. Pools of either gas will present a significant cryogenic risk to staff. Hydrogen will evaporate quicker than natural gas, and outdoors it will dissipate quicker than natural gas.

Indoors, immediately after vaporisation, both gases will be heavier than air and collect in low areas, where they present a significant risk (and may not be detected with high level gas detectors). However, the buoyancy of hydrogen means its temperature only needs to rise 2°C above the evaporation temperature for it to rise and dissipate, while methane needs to rise in temperature 53°C before it is more buoyant than air. Therefore, evaporated methane is more likely to collect at low level, presenting a hazard for longer.

As before, hydrogen presents a higher risk due to its higher likelihood of both igniting and detonating. However, the behaviour of GH_2 and LH_2 are well known and the hazards of an indoor leak will be dealt with at a design and certification stage with Computational Fluid Dynamics (CFD) modelling of venting systems.

7.2.4 Hydrogen Embrittlement

One issue with hydrogen that does not arise with natural gas, is its propensity to embrittle materials. In the last 15 to 20 years a failure mechanism known as Hydrogen Induced Stress Cracking (HISC) has had an increasing effect on the design of subsea systems. HISC is caused by a combination of three factors: tensile stress in the material, a susceptible microstructure and a hydrogen source. A recognition of the research performed on HISC will be accounted for when reviewing material selection for proposed offloading systems.

Nevertheless, the materials which should and should not be used for constructing hydrogen systems are well understood by industry. Consequently, hydrogen is created, stored and transported in large quantities every day without incident. The key is to avoid high-strength steels and instead use austenitic steels, such as 304 and 316 stainless steels. Conveniently, austenitic steels are also suitable for cryogenic applications, meaning that they are suitable for both GH_2 and LH_2.

7.2.5 Onboard Safety Considerations

Hydrogen in land-based use is well understood and can be considered safe, given the appropriate precautions. Marine use of hydrogen as a fuel is now evolving from being used in small scale applications in protected waterways to larger scales and less protected environments. The use of liquefied hydrogen is also now being introduced to the industry. Hazard identification and risk analysis are performed during design and appropriate measures are taken to provide an adequate safety level on ships. The development of classification rules specific to hydrogen applications aboard ships and the collaboration with Classification Societies and Flag Administrations during projects are building towards establishing safety standards and recommended practices.

7.2.6 Conclusion of Safety Comparison between Hydrogen and Natural Gas

Hydrogen and natural gas are both flammable fuel gases and present similar risks. Both have been used in industry for many decades, with examples of hydrogen being used in transport for everything from cars to submarines to rockets. Both hydrogen and natural gas are well understood by engineers and safe systems are perfectly possible to design and are in operation on vessels today.

In general terms, it is considered that hydrogen and natural gas present broadly similar hazards, with natural gas being more hazardous in outdoor situations and hydrogen more hazardous indoors. For liquefied gas, the hazards are broadly similar, with hydrogen evaporating quicker and igniting easier, but becoming more buoyant than air quicker and dissipating faster.

8.0 CONCLUSION

Green hydrogen has the potential to play a major part of a transition to a zero-carbon shipping industry. This shipping review is intended to provide an initial outline assessment of the current technological status of hydrogen in ports and on ships.

8.1 State of Marinized Hydrogen Technology

The rapidly increasing number of hydrogen projects in shipping and marinized hydrogen system TRLs are testimony of the feasibility of hydrogen to be used as an energy source aboard watercraft of different types and sizes. It is a maturing technology with an increasingly growing interest from stakeholders and a very high potential to solve many environmental issues associated with shipping today. Of all the reviewed projects, around a third were announced alone in 2019 or later.

The current state of the technology for hydrogen-based power trains in ships is at the development and demonstration stage. The TRLs are assessed in Table 9, Section 6.4 and, in summary, liquified storage is TRL 7, bunkering systems are TRL 6-7, PEM fuel cells are TRL 8-9 and hydrogen motors are TRL 6.

The accommodation for onboard hydrogen storage and its cost are particular challenges for current marine hydrogen technology. Storage in compressed gas or liquefied form poses a challenge insofar as, in order to accommodate it onboard and to maintain the same payload capacity, many ship types (but not all) would be required to increase in size. This would increase the construction cost of such ships. At present, hydrogen plants require an additional investment cost, which is expected to decrease with technological developments and larger production volumes.

Another challenge is the cost of hydrogen itself which, at present, is also higher than fuel oils. However, it is expected that the introduction of favourable policies (carbon pricing, for example) might considerably alter prices in favour of green hydrogen. If zero-carbon shipping is to be achieved, a transition away from fossil fuels (including LNG) is necessary. The AHOY high-uptake scenario (MAN, 2020) based on the MATISSE-SHIP model (Köhler, 2019; 2020) shows that if sufficient support for the further development of hydrogen technologies enables production and operation costs to begin to reduce through the learning effects of R&D and experience in producing and installing hydrogen systems, a major market for hydrogen in shipping can develop by 2030.

As seen in Section 6.3.1, hydrogen fuel cell outputs are increasing rapidly and expected to reach levels that would be suitable for ships engaged in international voyages in the foreseeable future. The current lack of international regulation of hydrogen plants aboard ships and delays in its adoption might present a barrier for such projects, despite their technologically feasibility.

8.2 Developments of Hydrogen in Ports

Ports with high H_2 Development but low H_2 Potential are expected to be reliant on collaboration with nearby ports that will have larger hydrogen production capacity. However, the nature of alternative fuels means that many more bunkering locations will be required than for fossil fuels. This increases opportunities for collaboration between ports which can be achieved through international initiatives such as the Clydebank Declaration and EU Green Ports (Mayet, 2017; European Commission, 2020b).

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