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Table of contents

Abbreviations

CH2	compressed hydrogen
HRS	Hydrogen refilling station
LCOE	Levelized cost of energy
LH2	liquid hydrogen
LOHC	Liquid organic hydrogen carrier
LHV	Lower heating value
MeOH	Methanol
MEGC	multi element gas container
RCS	Regulation, Codes and Standards
TCO	Total cost of ownership
TEU	Twenty feet equivalent unit
WACC	weighted average cost of capital

1 Introduction

The EU has set concrete targets to reduce the greenhouse emissions in the transport sector. This must be done not only in road transport although this has the highest percentage. All transport modes must reduce their share, be it road, rail or ship. The solutions might be different for each sector, but when it comes to larger vehicles operating on long distances, hydrogen is regarded as being the most suitable solution. Hydrogen offers long driving ranges and short refueling times together with high remaining transport capacities. Furthermore, hydrogen allows sector coupling between the energy, the transport and the industry sector.

In order to support the development and market introduction of emission free inland shipping, the network “RH2INE” was launched. The Rhine Hydrogen Integration Network of Excellence (RH2INE) is an international program and consists of public and private parties. Its global aim is to implement hydrogen as a fuel in the inland waterway transport (IWT).

The key barriers for the implementation of hydrogen in the inland waterway transportation sector are the lack of HRS and the scarcity of hydrogen-powered vessels. Several hydrogen and transport companies are ready to invest in hydrogen-powered vessels and in HRS. The RH2INE program has the objective to join forces in this process by initiating a so-called “kick-start study”.

The “kick-start study” consists of four (4) sub-studies. The sub-studies are:

- Sub-study 1a – Technical scenarios for ships and filling stations;
- Sub-study 1b – Safety and regulatory analysis
- Sub-study 2 – Design study
- Sub-study 3 – Location study

The present report includes the “Design Study”. While the previous reports covered more general aspects, this specific study deals with the concept of the refueling of the fuel cell ships with hydrogen and the design of the refueling station. Although various storage concepts for hydrogen were described in sub-study 1a – gaseous hydrogen, liquid hydrogen, ammonia - we will focus on the usage of gaseous hydrogen as energy carrier for the fuel cell ships. The decision was made by reflecting the current state of technology and the availability of the specific forms of hydrogen. The most common fuel cell today is the PEM fuel cell which needs pure hydrogen. The typical way to deliver this hydrogen is by transport in gaseous form. As only very few liquifying plants exist in Europe, the production and transport capacities of LH2 are very limited. With regard to ammonia, one has to admit that fuel cell systems based on ammonia reforming are still in an early development phase. Therefore, it is most likely that the market introduction of fuel cell inland vessels will be based on storage concepts using gaseous hydrogen.

In this study it will be described how the storage of hydrogen in swappable containers can be realized. The previous studies have demonstrated that hydrogen tanks built in the vessels will take a longer time for certification and permissions so that an external storage is favorized. A swappable container is also easy to store on container ships, the type of ships which is preferred by the shippers in the RH2INE consortium.

On the basis of different scenarios with regard to the number of ships the necessary number of containers will be calculated and a swap concept will be presented. The necessary hydrogen demand is forecasted assuming a certain number of round trips per week and ship using the energy demand calculations from other studies. Furthermore, hydrogen generation costs from electrolysis with green electricity including the necessary refilling plant (both at the port or nearby) will be calculated. Based on these numbers, assumptions on the TCO can be made. Finally, a cost benefit analysis is done to compare the CO_2 reduction costs with the external costs of emissions.

2 Input from sub-study 1 – Safety framework conditions

Sub study 2 is based on results of sub study 1. Thus, the most important information from sub study 1 [1–4] regarding to preferred bunkering scenarios and hydrogen demand is given below:

Hydrogen bunkering

- Short term bunkering will be preferably done with compressed hydrogen (CH2) in swappable containers with pressure from 200 to 500 bar. Fixed on bord systems seem only to be favorable for small applications such as ferries with limited energy consumption and little space onboard.
- Mid-term bunkering will be probably liquid hydrogen (LH2) in swappable containers or bunkering via hose.
- Long-term bunkering is seen with some hydrogen based liquid fuels like LOHC or sodium borohydride (NaBH4). Determination is nowadays not possible, especially having options as ammonia in mind.

Hydrogen demand

Until February 21 we only had access to a draft report, where based on different scenarios (see sub study 1 [5]) a wide range of hydrogen is assumed

Table 1: Hydrogen demand dependent on different scenarios [5]

Hydrogen [t/year]	Scenario 1	Scenario 2	Scenario 3
Year 2030	5.000	18.000	48.000
Year 2040	10.000	36.000	104.000

Based on these data with different concepts for short to long term bunkering scenarios the decision was made to concentrate on the short-term option using CH2, that enables the rapid introduction of hydrogen on ships on the Rhine. This will be followed by discussions in how far the mid-term option using liquid hydrogen can be integrated into this scenario.

3 Technical comparison of the bunkering scenarios

If using CH2 in swappable containers for inland navigation several questions occur regarding the infrastructure and different parts of the bunkering process containing the hydrogen supply, the container filling plant, the transportation of containers and handling in the port (see Figure 1).

Figure 1: Bunkering concept using swappable containers

- Which pressure is economically favorable? (the higher the pressure the higher the energy density)
- How many containers are necessary?
- Where will the containers be stored?
- How much does transportation of containers cost?
- Where will the containers be filled?
- How will the hydrogen be produced?
- And where will the hydrogen be produced
- How many containers must be filled per hour/day/….?
- Which components are necessary depending on filling location?
- Are there limits or restriction at the harbor?
- What is about RCS?
- …

3.1 Hydrogen demand at bunker / swap station

For looking into bunkering systems, the amount of hydrogen bunkered per hour/day/week must be known. Therefore, the demand of ships must be estimated to decide if bunkering and storage on ship fits for the requirements.

In comparison to trucks, trains or cars where an average fuel consumption for special classes, e.g. 40 t-truck, in l/km can easily be given it is more complex in inland navigation. Even if concentrating on cargo vessels there is a wide variation of ship types starting with small barges of the Karl Vortisch type with a length of 38-41 meters and a power from 100 kW over barges of the Johann-Welker class with a length from 86 to 100 m and typical GMS types with length up to 135 m and a power up to 2500 kW. Additionally, the load influences the fuel consumption. But the biggest difference to land based transportation is the waterway itself with very different flow conditions. The power demand on a canal or the downstream route on a river is much lower than the upstream route. E.g., on the roundtrip Nijmegen – Duisburg – Nijmegen approx. 70% of the power is needed on the journey upstream [6] .

For estimations of the hydrogen demand at bunker stations some assumptions must be made. The following calculations are based on the Containership “Monika Deymann”, a 135 m long ship with a width of 14,20 m and a capacity of 421 TEU. By choosing such a big ship as example it can be assured that the dimensioning of the bunker facilities and regarding infrastructure is sufficient as well for smaller ships with lower energy demands. Additionally, some load profiles for the relation Nijmegen-Duisburg for this ship are available [7]. To focus on the relevant roundtrip Rotterdam – Duisburg these profiles were extrapolated by assuming that the characteristics of the Rhine don't change too much from Nijmegen downstream to Rotterdam.

Based on the load profiles at the propeller the hydrogen demand of the ship is calculated with efficiencies for the fuel cell (η = 50%) and the efficiencies for frequency converter and electric motor (η = 91,2%). Figure 1 shows the estimations for the hydrogen demands for maximum, minimum and average load profile.

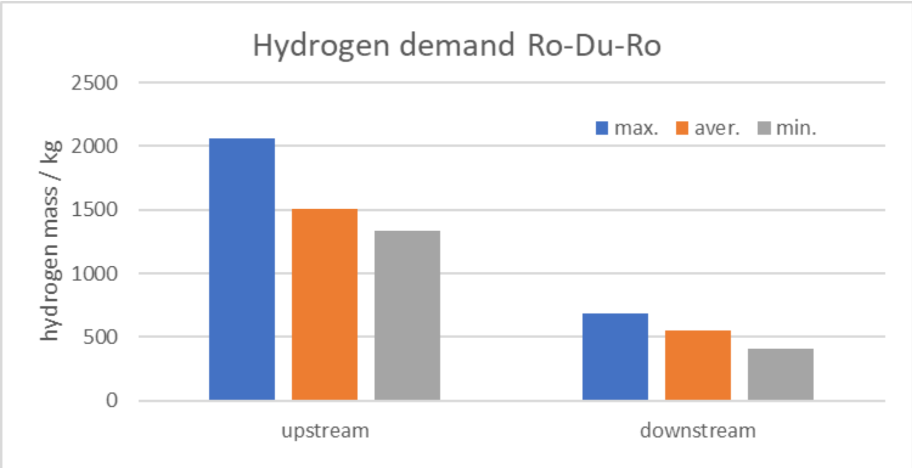


Figure 2: Estimated hydrogen demand for the Container ship "Monika Deymann" on the roundtrip Rotterdam -Duisburg (based on [7])

For one ship and one round trip a hydrogen mass of 1,8 to 2,8 t is needed. With 3 roundtrips a week (24/7 operational mode) this would mean a maximum yearly hydrogen consumption of about 400 t. Assuming to have two bunkering stations at the end points of the route when starting with hydrogen on ships it is important to have the different demands for upstream and downstream in mind, which in the case under consideration are in the ratio 70%/30%. This information is needed in chapter 3.2.2 where the number of containers is estimated.

3.2 CHG Container

3.2.1 Container Types

Sub study 1 proposes CH2 in swappable containers for hydrogen storage, transport and bunkering. Typical container-based storage systems are built of the container shell and cylinders containing the hydrogen. Different types of storage cylinder can be considered:

- Type 1: steel cylinder
- Type 2: cylinders with a metal liner (steel or alu) partially wrapped with carbon fibers
- Type 3: cylinders with a metal liner (steel or alu) fully wrapped with carbon fibers
- Type 4: composite cylinder made of a polymer liner and fully wrapped with carbon fibers.

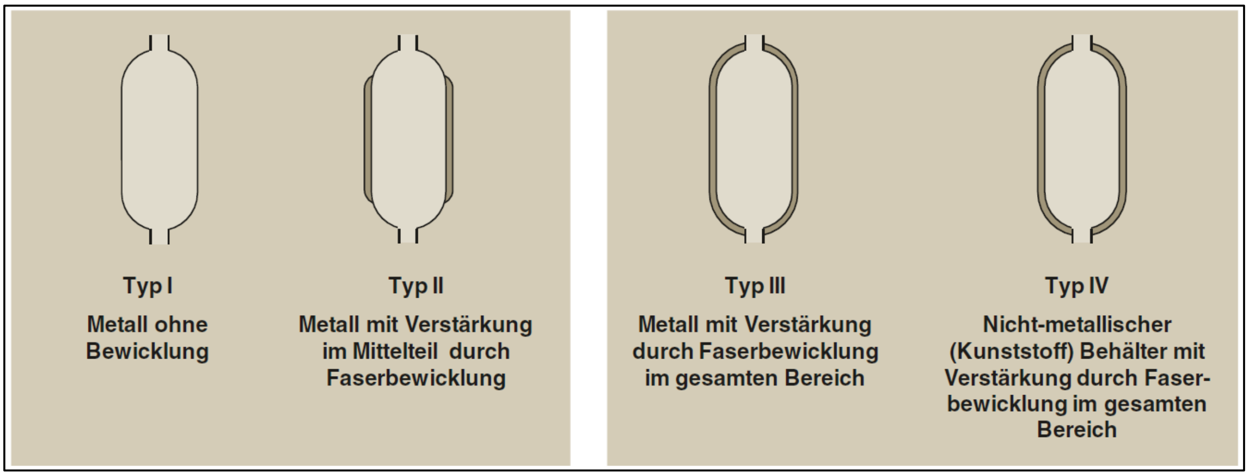


Figure 3: Types of storage cylinders [8]

The advantage of the type 1 and even type 2 cylinders are the low costs. Type 1 cylinders are typically used for different gases as single bottles or in bundles of 12 or 16 cylinders. Type 2 cylinders are often used in stationary applications for example as 1000 bar high pressure tank in HRS. Opposite to that the main advantage of type 4 cylinders is the low weight even for high pressures up to 700 bar. This is important for mobile applications; thus, vehicles are a typical application for these. However, the comparatively high costs are a disadvantage.

Most container-based hydrogen storage units work nowadays with pressures of 300 or 500 bar. 300 bar systems can incorporate type 1, type 2 or type 4 cylinders, 500 bar systems always consist of type 4 cylinders.

Containers are available in lengths of 10 ft, 20 ft and 40 ft. Considering that the containers have to be transported by truck and will be used in the future in different even smaller ships with different energy demands, the 20 ft-container seem to be the best choice. Additionally, talks with shipowners showed a preference of 20 ft containers as well. For small ships as ferries in a first step conventional bundles can be used. Figure 4 shows an example of a hydrogen storage container.

Figure 4: 20’-Container, 500 bar of company NPROXX

Table 2 lists the most important data of some 20 ft-containers with 300 bar with type 2 and type 4 cylinders as well as a 500 bar container with type 4 cylinders.

Table 2: Container data (datasheets of [9] and [10])

20ft-container	unit	300 bar	300 bar	500 bar
Storage system		MEGC[1]	MEGC	MEGC
Cylinder type		Type II	Type IV	Type IV
Dimensions	mm	6058 x 2550 x 2550	6058 x 2432 x 2743	6058 x 2438 x 2700
Cylinders		n/a	54	48
Storage capacity	kg H2	312 (@300 bar)	371 (@300 bar)	518 (10 -500 bar, 15°C)
Volumetric content	L	15.912	18.900	16.800
Weight (empty)	kg	21.000	9.250	14.000
Cost	€	~150 T€	~ 250 T€	~ 380 T€

The question which pressure to prefer is a tradeoff between costs and energy density: 300 bar containers have lower investment costs but 500 bar containers have higher energy density. The best choice may be different for different cases. Investment costs should always be low of course, but if operation is less expensive due to higher energy densities and thus less space on board and/or fewer bunkering stops are needed, the higher investment may lead to lower life cycle cost (see chapter 4.5.1). Regardless of this, for a functioning hydrogen infrastructure on the Rhine and in inland navigation it is very important to set one standard, to ensure exchangeability of the swappable containers! So, in detail we analyzed and compared bunkering systems for 300 bar and 500 bar.

3.2.2 Number of containers

The main difference between 300 and 500 bar containers besides price and weight is the hydrogen amount stored respectively the energy density. For an estimation how many containers are needed the described hydrogen demand for the reference ship in chapter 3.1 serves as a basis.

- 1 ship, 135 long, 421 TEU
- Roundtrip Rotterdam – Duisburg - Rotterdam
- 2 bunker stations: one upstream, one downstream
- Roundtrip of about 2 days, 3 times a week
- Hydrogen demand upstream max. 2 t and downstream around 0,7 t.
- At every station one spare container is placed in case of malfunctions or damages

Scenario one ship

Figure 5 explains the number of 500 bar containers needed for the case that the bigger filling plant is in Duisburg. (the same takes place if the bigger plant is in Rotterdam) During the upstream trip of the ship 2 empty containers are at filling plant A, 4 containers are on the ship needed for the way upstream and 4 full containers are waiting at port B. At the stop in port B the now empty containers of the ship are exchanged by the full containers of the port. During the downstream trip the empty containers are transported from port B to plant B and simultaneously the filled containers from filling plant A are transported to port A. Stopping at port A, two containers on the ship are still full and the two empty ones are exchanged with

[1] MEGC: Multiple-Element Gas Container

new the full ones. The ship has again 4 full containers for the upstream journey. With the spare containers in every port 12 containers in total are needed, with a maximum of 4 containers on the ship.

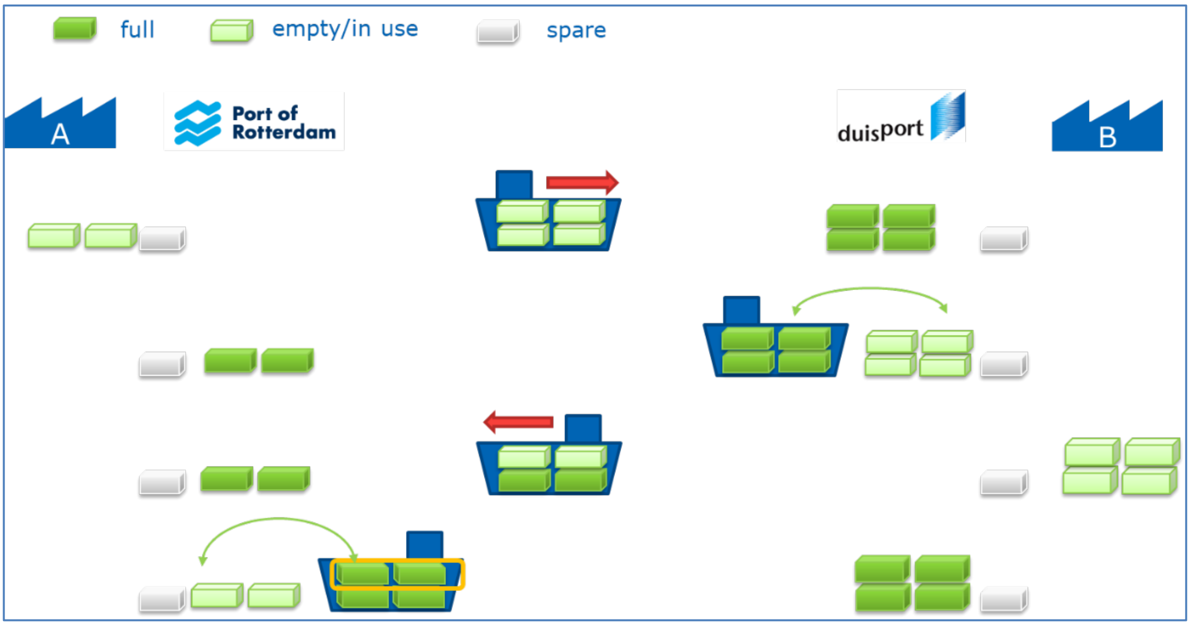


Figure 5: Number of 20 ft containers, 500 bar

This means that at filling plant A two containers must be transported and filled within two days, so a maximum of 1 t (2 x 500 kg) of hydrogen must be produced/delivered and filled in containers. At filling plant B 2 t (4 x 500 kg) of hydrogen must be provided within 2 days.

Using 300 bar containers means less hydrogen amount per container (see. Table 1) and thus more containers. For the presented ship - waterway relation upstream 6 containers are needed. Additionally, 6 full containers must be stored at the port B and 2 at port A, thus 14 containers plus 2 spare containers are needed here.

Scenario five ships

If 5 ships are in circulation the number of containers needed increases. With such a small amount of ships the worst case – all ships at nearly the same time at one port – is the basis for the calculations.

- About 50 containers (500 bar) are needed per roundtrip + 4 spare container
- Hydrogen production/filling (maximum)
- Filling plant A: 10 containers/2 days, that is 5 t within 2 days (2,5 t/day)
- Filling plant B: 20 containers/2days, that is 10 t within 2 days (5 t/day)

When using 300 bar containers about 70 containers plus 4 spare containers are needed.

Scenario 100 ships

If 100 ships are in circulation the worst case would be, if all ships are nearly at the same time in one port. Then a minimum of 1000 containers would be needed. This scenario is very unlikely. So, the number of containers is estimated with the following assumptions. Half of the ships are on the route and the other half is in the ports. At the ports the containers for the ships are stored and the same amount is filled at the filling plant.

Table 3: Container spread with 100 hydrogen fueled ships circulating

filling	port A	river	port B	filling
25*2=50	S: 25*4=100 P: 25*2=50	S: 50*4=200	S: 25*4=100 P: 25*4=100	25*4=100
S: ship, P: port				

Thus about 700 containers (500 bar) plus 20 to 30 spare containers are needed. At the filling plant up to 100 containers must be filled in about 24 hours, which means a maximum of 50 t per day. The numbers are valid for 2 filling plants and two exchange ports. It is assumed, that with increasing numbers of hydrogen fueled ships additional ports and filling plants will extend the hydrogen bunkering net.

For 300 bar containers the same estimations as described in Table 3 are made, thus getting 850 containers (300 bar) needed for the roundtrips plus 20 to 30 spare containers.

3.3 Liquid Hydrogen

In the previous study liquid hydrogen (LH2) is assumed to be the energy carrier for inland navigation in the midterm. The advantage of LH2 is the higher volumetric energy density with 2359 kWh/m³ in opposite to 1115 kWh/m³ at 500 bar or 750 kWh/m³ at 300 bar. The main disadvantages are the high energy demand for liquefaction of about more than 30% of the LHV of hydrogen [11, 12] (500 bar compression needs about 6 to 10% of LHV depending on input pressure) and the boil off, which can't be avoided with longer standing times. The latter is in inland navigation not the problem, because of energy demands e.g. for living, pumps etc. is needed even during rest times. The former must be traded off with transportation, range, costs and economics.

Provision of LH2
Liquefaction of hydrogen takes place in complex plants, thus bigger centralized plants are used. In Germany exist only two Linde plants in Leuna (6 t/d) and Ingolstadt (5 t/d) [11, 13]. In the Netherlands one is operated by Air Products in Rotterdam (6 t/d) [14] and one in Waziers/France with 12 t/d [15, 16] In opposite to CH2, LH2 will always be produced central and then be delivered to ports or bunkering locations. This can happen by ship, train or truck. For the transportation with trucks normally trailers with capacities up to 3,5 t of LH2 are used. "Current designs for ships rely on IMO type C" [17][1] super insulated vacuum tanks. LH2 tanks are as well available in ISO containers for road or train transport, but swap ability especially for ships seems to be problem until today [1]. Up to now LH2-tank vessels for inland navigation do not exist.

Using liquid hydrogen in inland navigation offers two ways of bunkering: similar to compressed hydrogen LH2 can be stored in insulated tank-containers and swapped if it is possible and allowed in future or it can be pumped to the ship from shore, ship or truck similar to LNG-bunkering.

LH2 in tank-container

LH2 can be stored in tank containers, which would be similar to CH2 containers in terms of handling. However DNV GL notes in their study “Swappable liquid hydrogen tank-containers will most likely not be applied in shipping due the safety risks associated with hoisting” (see [5]). Provided the safety issues can be resolved, CH2 containers could be replaced with LH2-tank-containers. Special technical features for vaporization etc. could be as well containerized. So, if in some years liquid hydrogen will be favored, ships need on the technical side not much change. It only must be ensured that hydrogen with proper pressure and temperature is delivered to the fuel cell or motor.

Tank-containers would be filled at some few centralized liquefaction plants, ideally located somewhere near some ports (as in Rotterdam [14]). The tank-containers will be delivered to ports or other application by train, truck of ship.

Bunkering via hose

Should LH2 become established, the fixed installation of storage systems on board of ships is a good option, especially for new builds. Fixed – not swappable – containerized systems are a good option for existing ships as well and ships, that used CH2 in containers before. Bunkering of cryogenic fuels by hose is proven through LNG bunkering. Bunkering can be performed from shore, truck or ship. Especially in the beginning of using LH2 bunkering via truck will be necessary until bunkering stations or bunkering ships with similar concepts as for LNG bunker barges [18] will be build.

As mentioned above LH2 will always be produced centrally or it will be imported e.g., via Rotterdam. Thus, distribution systems must be developed. Pipeline systems are rather unlikely from today’s point of view. So large quantities must be transported by ship and train, smaller quantities by truck.

4 Technical equipment and estimated costs

4.1 System boundaries of bunker station and infrastructure

If using swappable containers there is no real bunker station similar to hydrogen refueling stations for vehicles necessary. The whole system consists of parts shown in Figure 6. Inhere the filling plant is besides the containers itself the most important part of the system.

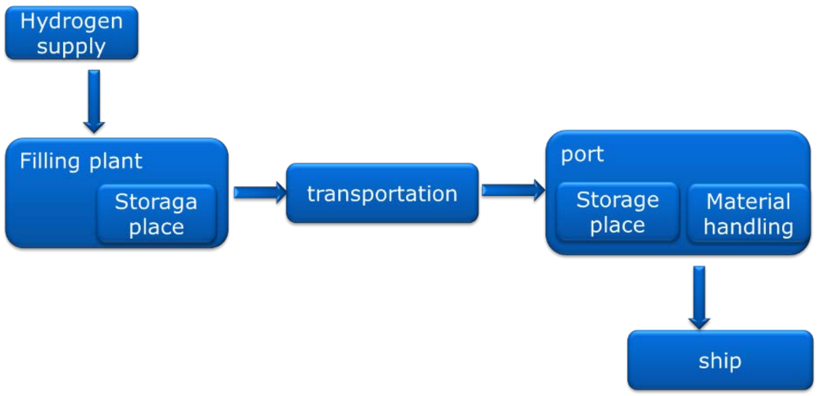


Figure 6: Bunkering principle with swappable containers

It was chosen to count the filling plant to the bunkering scenario although if it is as well belonging to infrastructure when using as part of energy storage for fluctuating renewable energies such as wind or solar energy or as part of a hydrogen economy where containers are used for HRS storage or kind of hydrogen transport. In the following the equipment for the filling plant as well as the containers and storage and transportation are considered.

4.2 Hydrogen supply

In the further explanations it is assumed that always green hydrogen is meant or excess hydrogen from chemical processes.

Hydrogen production

There are different options of suppling hydrogen to the filling plant. Nowadays most of the hydrogen is produced by steam reforming of natural gas, but this shouldn't be the way for the future due to finite resources and the CO2 problem. Some chemical processes like the Chlorine-alkali electrolysis produce hydrogen as a by-product, but it is assumed that most of the hydrogen needed in future will be produced by water electrolysis fed with renewable electricity. Where energy and space are available the production of hydrogen directly at the filling plant is a good option in order to avoid transportation costs and losses due to compression and re-filling or other processes necessary to transport hydrogen. Electrolysis systems often deliver hydrogen dry at pressures between 10 to 30 bar otherwise a drying unit must be installed.

H2 generation costs

One important question will be the price for hydrogen. In order to compare the calculations of the hydrogen production costs of the different plants, the net present value method is used. For all calculations, a weighted average cost of capital (WACC) of 3.45% is assumed, regardless of the hydrogen or electricity source. The real WACC is composed of the proportionate return (10%) on equity (30%) plus the proportionate return (3.5%) on debt

(70%) minus the inflation rate (2%). The real WACC is based on the study by Fraunhofer ISE "Stromgestehungskosten Erneuerbare Energie" from 2018 [19].

The price of hydrogen calculated using the Levelised Cost of Energy (LCOE) method corresponds to the minimum price for which hydrogen would have to be sold in order to recover both the capital employed and the corresponding return on equity and debt. The LCOE for hydrogen is calculated from the investment costs divided by the full load hours (FLH) of the electrolyser, as well as the capital costs over the lifetime of the plant. It corresponds to the real interest rate (WACC real).

$$LCOE = \frac{I_0}{\text{VLS} \cdot \sum_{t=1}^{n=20} \frac{1}{(1+i)^t}}$$

Furthermore, it is assumed that 50 kWh/kg are required to produce hydrogen by means of electrolysis. This corresponds to a realistic efficiency of 67% of the electrolysis plant based on the lower heating value (LHV) of hydrogen of 33.33 kWh/kg. Especially for future plants, it can be assumed that the efficiency will continue to increase and that the assumption is therefore rather conservative. The operating costs of the electrolysis plant without electricity and water consumption, which also include the replacement of degraded stacks, are assumed to be 2% according to the literature. The lifetime of the plants is assumed to be 20 years each with 160,000 operating hours and 8000 full load hours per year.

The values for the electricity prices were obtained through expert surveys [20].
The construction and infrastructure costs for a PEM electrolysis plant are assumed to be 20 % of the investment costs. These include both the laying of appropriate foundations and the construction of electricity and gas connections and were estimated from empirical values.

The costs of the storage tanks are not included in the calculations of the specific hydrogen production costs. For a 500 kg storage tank with 50 bar, such as can be found at many hydrogen filling stattions, investment costs of 150,000 € are estimated. Such a storage tank has a diameter of 2.80 m, a surface area of approx. 50 m2 and a height of 22 m. For a higher storage capacity, the costs would have to be calculated, as several of these reservoirs or a larger reservoir with a higher pressure level would have to be built. Values for these are not yet available. However, it can be assumed that the investment costs for higher-capacity storage tanks are lower than the sum of the combination of several 500 kg storage tanks.

With § 69b EEG 2021 - which will only be applicable after the ordinance pursuant to § 93 EEG 2021, which is to define the requirements for green hydrogen production, has been issued - green hydrogen production by means of electrolysis is to be fully exempt from EEG levies in future. Even though a legally binding definition of green hydrogen has not yet been made, an EEG levy exemption is assumed for the calculations. This premise was chosen because only with an exemption from the EEG surcharges would it make sense to operate the electrolysis plants economically, otherwise no investment would be made. (Balanced) wind and PV electricity will definitely be designated as an electricity source for green hydrogen.

Grid charges only apply if the electricity is drawn from the general supply grid. In this case, there is a full exemption option for the electricity purchased by the electrolyser under section 118(6) sentences 1, 7 and 8 EnWG. The grid charges are assumed to be zero in the calculation accordingly.

For the electricity tax, full relief under § 9a para. 1 no. 1 StromStG is possible if the company operating the electrolyser is a manufacturing company. The electricity tax is assumed to be zero in the calculation.

Case 1 : 3 MWel PEM electrolysis; 8000h; 1 vessel

The first example is calculated for a 3 MW_{el} PEM electrolysis for the production of hydrogen at the Duisburg site. The electricity for the electrolysis is a green electricity tariff (on balance sheet). The water fuel requirement is geared to the refuelling of 1 ship.

Table 4: Input data for 3 MW electrolysis H2 cost estimation

Technology		Economic efficiency	
Technology	PEM	**Investment Electrolysis**	3,60 Mio€
Electrical Power	3 MW	**Investment construction/infrastructure**	0,72 Mio€
Efficiency	67 %	**Investment compressor**	n/a
Voltage connection	10 kV	**Total investment (excluding storage)**	4,32 Mio€
H2-Production	1315 kg/d	**Real interest rate (WACC real)**	5,14 %
Water demand	4,3 Mio. l/a	**Operating and maintenance costs**	2 % of the investment
H2 storage size	3945 kg (for 3 days)	**Investment storage**	150.000 € per 500 kg tank
H2 compressor	n/a	**Average electricity price**	4,0 ct/kWh
Space requirement (excluding storage)	500 m2	**EEG levy**	6,5 ct/kWh
Output pressure electrolysis	30-76 bar	**Other levies**	0,68 ct/kWh
Storage pressure	50 bar	**Specific electrolysis costs**	1200 €/kW
Full load hours	8000 h	**Factor production costs**	12,32

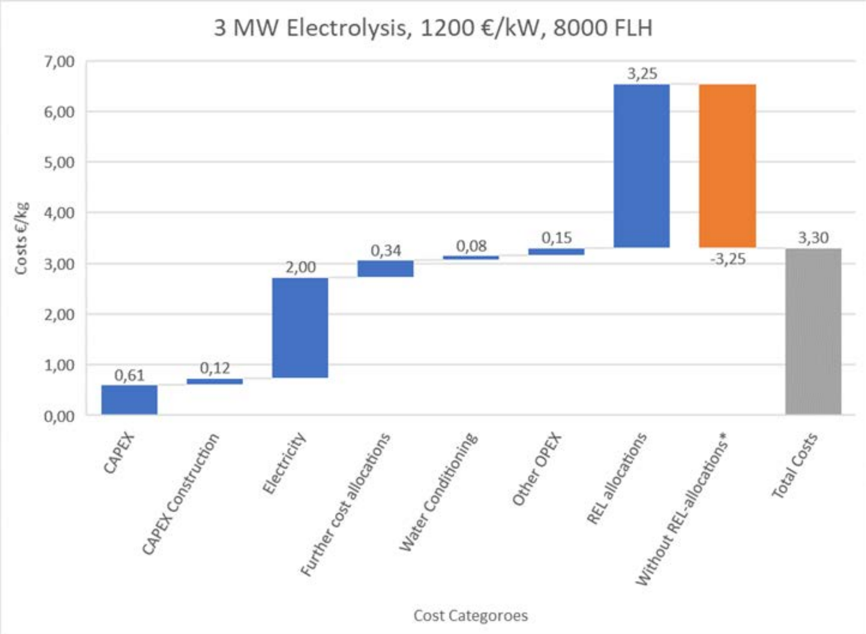


Figure 7:Hydrogen price for 3 MW electrolysis

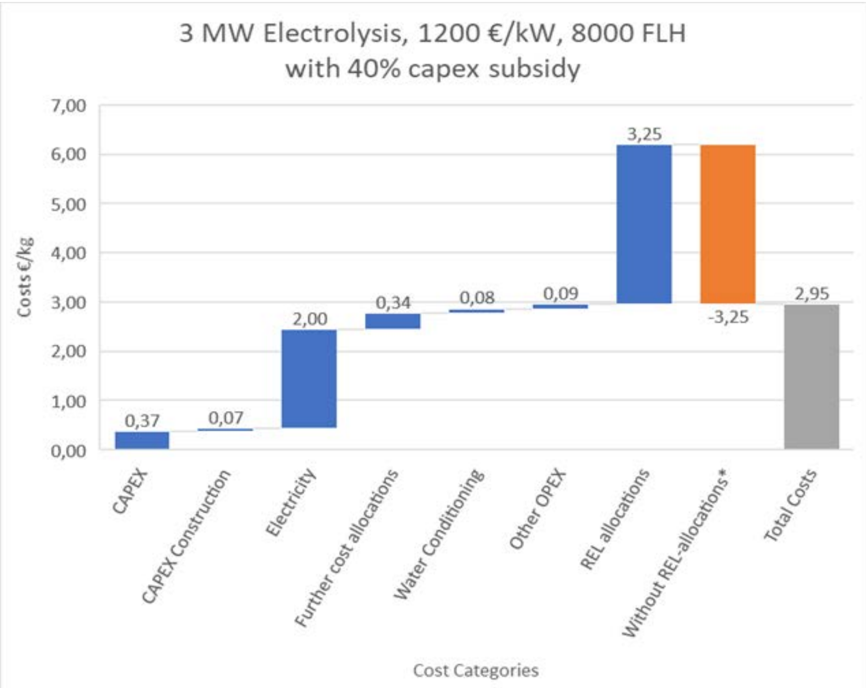


Figure 8: Hydrogen price for 3 MW electrolysis with capex subsidy of 40%

Figure 7 shows the different shares from capex over electriciy cost to other opex cost. Thus the total costs for hydrogen will be about 3,30€/kg of hydrogen based on the input data of Table 4. If a subsidy of 40% can be used the price decreases to 2,95 €/kg (see Figure 8).

Case 2 : 12 MWel PEM electrolysis; 8000h; 5 vessels

12 MW_{el} PEM electrolysis for the production of hydrogen at the Duisburg site The electricity for the electrolysis is a green electricity tariff (on balance sheet). The hydrogen demand is designed for the refuelling of 5 ships.

Table 5: Input data for 12 MW electrolysis H2 cost estimation

Technology		Economic efficiency	
Technology	PEM	**Investment Electrolysis**	8,4 Mio€
Electrical Power	12 MW	**Investment construction/infrastructure**	1,08 Mio€
Efficiency	67 %	**Investment compressor**	n/a
Voltage connection	10 kV	**Total investment (excluding storage)**	10,08 Mio€
H2-Production	5260 kg/d	**Real interest rate (WACC real)**	5,14 %
Water demand	17,28 Mio. l/a	**Operating and maintenance costs**	2 % der Investition
H2 storage size	15.781 kg (for 3 days	**Investment storage**	150.000 € per 500 kg tank
H2 compressor	n/a	**Average electricity price**	4,0 ct/kWh
Space requirement (excluding storage)	1000 m2	**EEG levy**	6,5 ct/kWh
Output pressure electrolysis	30-76 bar	**Other levies**	0,68 ct/kWh
Storage pressure	50 bar	**Specific electrolysis costs**	700 €/kW
Full load hours	8000 h	**Factor production costs**	12,32

The hydrogen price decreases with higher demand and the bigger electrolyser to 2,94 €/kg without subsidy and decreases by another 21 ct/kg to 2,73€/kg when a subsidy of 40% is used.

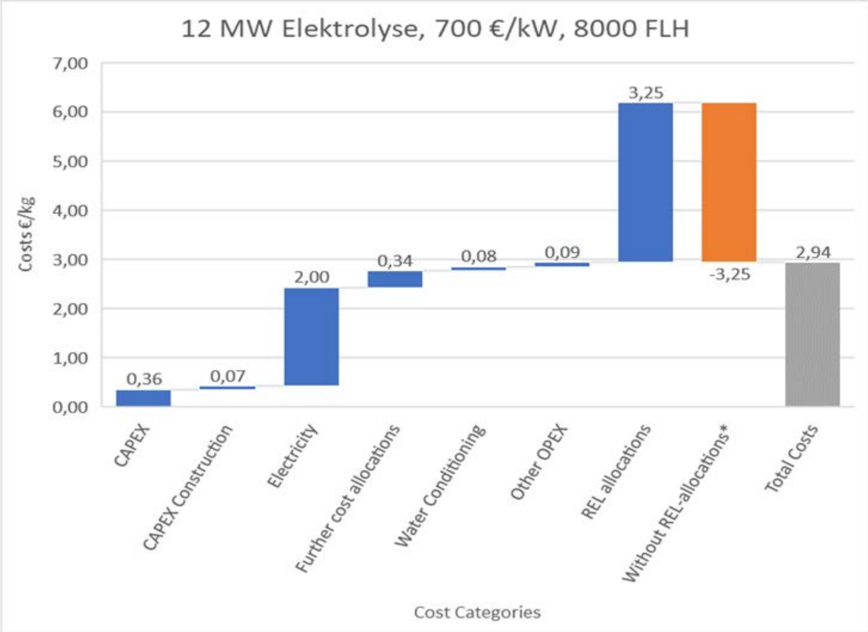


Figure 9: Hydrogen price for 12 MW electrolysis

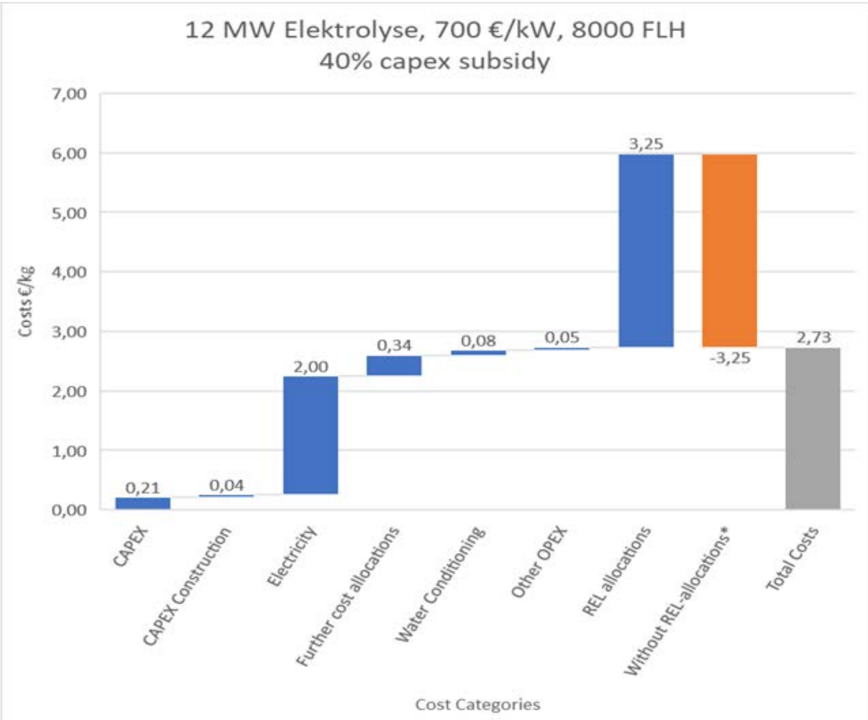


Figure 10: Hydrogen price for 12 MW electrolysis with capex subsidy of 40 %

It can be assumed that the price of hydrogen will continue to fall by even larger plants and that the investment costs for electrolysers will fall as a result of further developments. However, the graphs also show that the electricity price - which is already low at the 4 ct/kWh assumed here - accounts for the largest share of the hydrogen price.

4.3 Hydrogen delivery to filling plant

A combination of hydrogen generation and filling plant seems to be the best option. If this is not possible there are different ways to deliver hydrogen to the plant.

CH2 in Pipelines

Central produced hydrogen can be delivered to the filling plants via pipelines. In addition to the existing pure H2 pipelines, work is currently underway on the rededication of natural gas pipelines, which will also be used for hydrogen transport in the future. To use hydrogen from pipelines a cleaning unit must be incorporated in the filling plant

LH2 in trucks / train

Another supply option is LH2. This kind of hydrogen delivery seems interesting because of the amount of up to 3,5 t of hydrogen that can be transported with one truck. But liquefaction needs much energy (nowadays more than 30% of hydrogen LHV). Using liquid hydrogen can avoid costly compressors by using cryogenic pumps thus getting gaseous hydrogen at suitable pressures.

Hydrogen carrier as LOHC, NH3, MeOH or NaBH4

Hydrogen can be stored and transported as well in chemical bounded form. Examples here for are liquid organic hydrogen carrier (LOHC), ammonia (NH3), methanol (MeOH) or sodium borohydride (NaBH4) which are shortly discussed below with regard to their transport properties and use as hydrogen carrier.

LOHC is mostly based on oily liquids and can be handled and transported similar to diesel. Thus, it can easily be transported by truck or train to a filling plant. Via a dehydrogenation unit the hydrogen can be released of the LOHC. This is an endothermic process taking place in a complex plant needing energy in a range of about 30% of the LHV of hydrogen. Additionally, gas cleaning must be provided to guarantee the quality of the product gas and not having traces of oil.

Ammonia is a long-known product transported and handled in fertilizer industry. Ammonia is liquid at temperatures below -33 °C (at 1 bar) or at pressures over 9 bar (at 20°C). It can be cracked to N2 and H2, thus being carbon free. The cracking process especially in bigger dimensions with high hydrogen quality is not a conventional process up to now. Also, it must be assured that no NH3 traces remain in the hydrogen.

Sodium borohydride is a material-based hydrogen storage option, but not a mature technology up to now. Similar to LOHC or ammonia a hydrogen release unit is necessary.

4.4 Filling plant

4.4.1 Filling plant design

The filling plant consists of the hydrogen treatment unit depending on the kind of hydrogen supply, some buffers, a compressor, the filling device and some piping, valves and the measurement and control technology.

Because of the different opportunities for the hydrogen supply the treatment will not be discussed in detail. An estimation of necessary/available techniques and their mature and costs is given in chapter 5.3.1. It is supposed that hydrogen is provided dry and with a pressure of up to 30 bar.

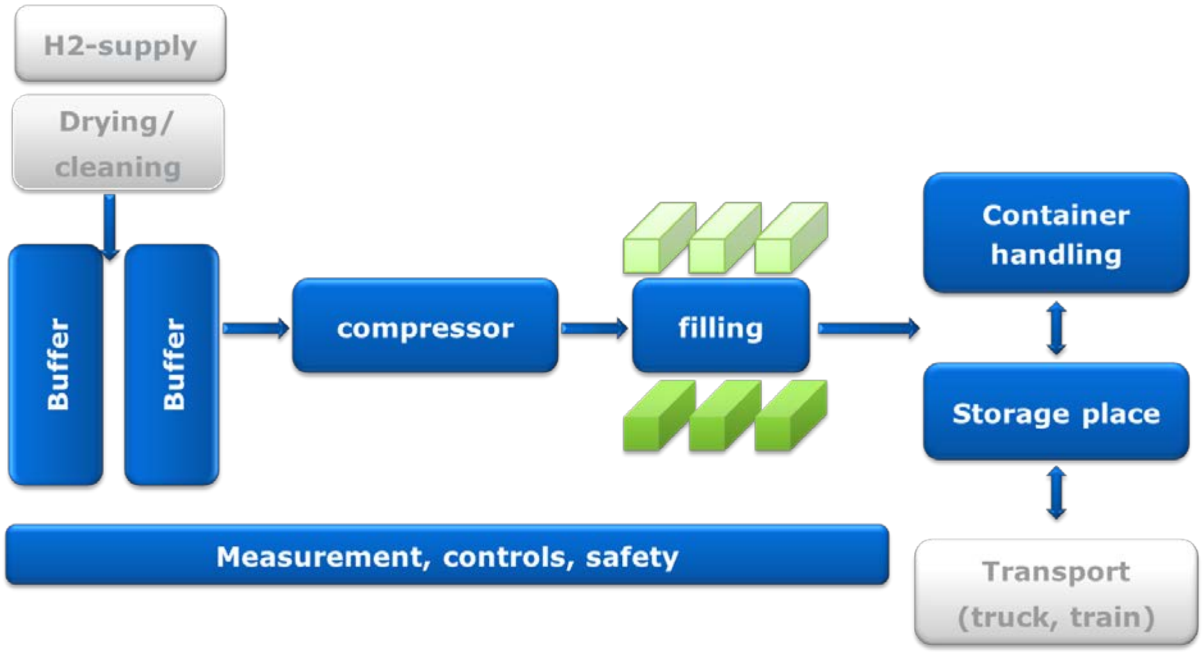


Figure 11: Main parts of filling plant

First of all, some **buffers** for hydrogen must be installed. This is especially necessary when the hydrogen production or delivery process cannot be adjusted to the consumption of the filling process. Additionally, it prevents the system from pressure fluctuations which occur from compression [21]. Different types of buffers can be considered. Typical low-pressure buffers are suitable for pressures up to 40 bar with capacities of about 200 kg. They might be useful for the first buffering of hydrogen coming directly from electrolysis but the capacity will not be sufficient as a buffer. Buffer with higher pressures in the range of 200 to 300 bar and capacities higher than 1,2 t must be installed.

In any case one or more **compressors** are needed. Hydrogen must be compressed from supply source, where pressure will be in the range of 10 to 30 bar to be fed to the buffer with up to 200 or 300 bar. In a second stage the compressor will fill the containers with a pressure of 500 bar. In principle, 2 types of compressors come into consideration: a non-lubricated piston compressor or a membrane compressor. In the beginning of the hydrogen economy piston compressor are preferable, because a continuous operation of the system cannot be ensured. Frequent starts and stops are a problem for the membranes in membrane compressors so that they can crack. For greater demands - and therefore an option for continuous operation - a membrane compressor is a good choice especially for lower maintenance costs [21].

4.4.2 Filling plant cost estimations

The largest items for cost estimation are the compressor and the buffers. The latter ones are in a range of 400 to 600 €/kgH2. The overall costs for the buffer depend on the system size and thus on the filling plant design. If continuous hydrogen delivery at defined pressure is possible the buffers can be smaller than at plants with discontinuous hydrogen supply.

Costs for the compressor are as well strongly dependent on the plant size. Just to fill one 500 bar container with a capacity of about 500 kg of hydrogen in 8 hours would require a compressor with a flow rate of 63 kg/h. Filling several containers in parallel requires accordingly much higher flow rates.

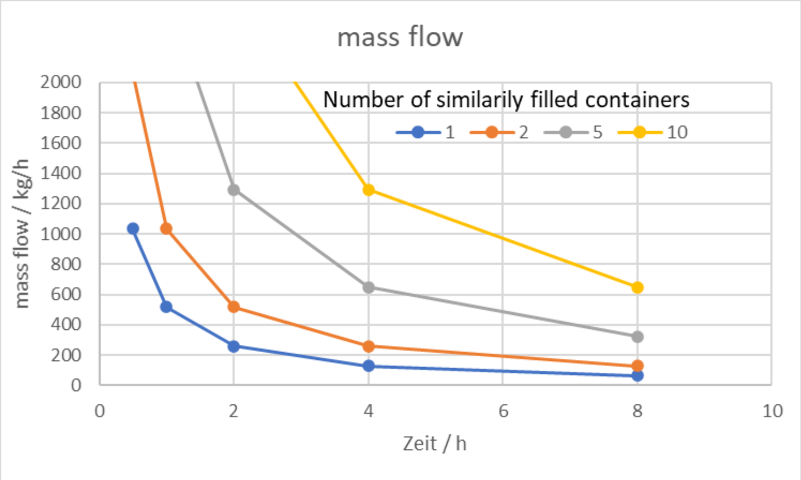


Figure 12: Compressor mass flows depending on time and number of containers

The costs for compressors in the range with a mass flow of about 50 kg/h are about 700.000€ [16, 22]. For hydrogen demands for up to 5 ships this value can be multiplied for higher rates eventually reduced by a quantity discount of 10 to 15%.

Furthermore, valves and piping are required for the filling station as well as the manifold for the container filling. Cost estimations from different companies therefore differ a lot. Beginning with about 200.000€ up to 400.000. Estimations for the technique of a filling station with a production/filling rate of 1t/day vary from 1,8 M€ to 2.5 M€. For filling rates of about 2t/day and an including buffer with 3 t of hydrogen costs of about 8 Mio€ were mentioned. Controls, safety concepts and instrumentations are included here. [16, 21–23]

Additional machinery necessary for handling the containers such as container fork lifts or reach stackers must be taken into account as well. Prices for these are between 130.000 and 250.000€ [24] [25].

Below some **detailed calculations** were performed to show the influence of the size of the filling plants. In case 1, the plant is designed for one ship, in case 2 for 5 ships. Data are based on the numbers given in a presentation by the company Neuman & Esser during the Hydrogen Online Workshop 2021 [21]. Neuman & Esser are manufacturers of e.g. H2 Compressors and have deep experience in the designing of such filling plants. The assumptions given here were furthermore proven in talks with other manufacturers. The price indications given in the following tables have their origin in that presentation.

Case 1 : 2 compressors, 1 vessel

As mentioned before a typical filling plant consists of compressors and low-pressure and medium pressure buffer tanks, an optional cooling unit, the manifold board for the coupling with the containers and the control unit. For the calculations a typical H2 compressor with a throughput of 50 kg H2/h was used. Neuman & Esser recommend a 2-stage diaphragm compressor with 40 bar input (coming from the electrolyser) compressing up to 500 bar, the design pressure for the containers. At least two of these are needed in order to reach the necessary daily amount of H2 to fill the containers. Compressors will need maintenance and spare sparts which is considered by a percentage of the CAPEX. The lifetime of the compressors is given with 20 years. The necessary electrical energy for the operation of the compressors is calculated on a daily operation of 12 h.

Table 6: Cost calculation data base: 2 compressors, 1 vessel

Data input		
CAPEX		
LP Buffer	€	500.000
Pre-Compressor	€	1.100.000
MP Buffer	€	1.000.000
Control	€	200000
OPEX		
Compressor Parts	% of Capex	2,5
Energy	€/kWh	0,04
Service	€/a	4.000
Technical parameters		
Duration	a	20
Power	kW	250
Operating hours	h/d	12
Capacity	kg/h	100
Economic parameters		
Interest rate	%	2

The following graph shows that the CAPEX and OPEX contribute with another 0,5 € on the kilogram price of the hydrogen. More than 60% are coming from the depreciation. If a 40% capex subsidy is assumed the depreciation decreases to 0,19 €/kg and thus the contribute decreases to 0,37 €/kg.

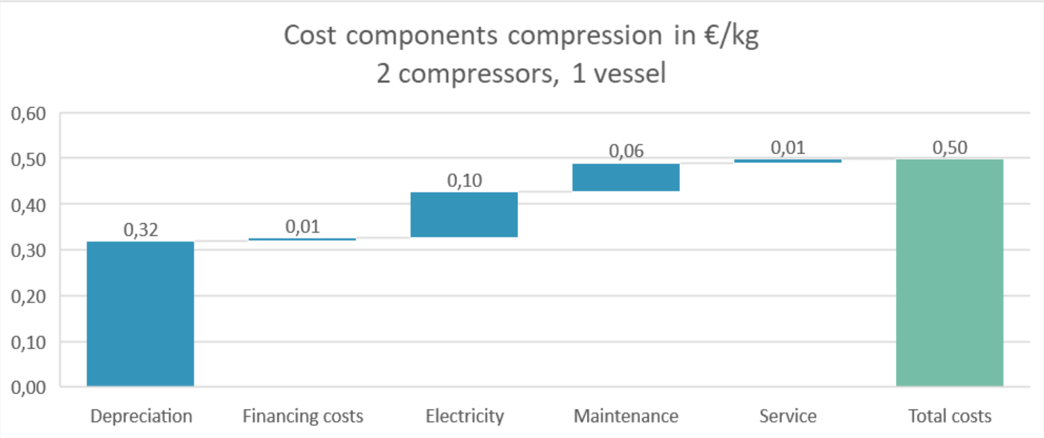


Figure 13: Influence of filling plant on H2 price; 2 compressors, 1 vessel

Case 2 : Cost components compression, 4 compressors, 5 vessels

For the refilling of the higher number of containers needed for 5 ships the number of compressors must be increased. Roughly 5 tons per day have to be filled into the containers. Therefore, we now calculate with 4 compressors. The number of buffers can stay the same.

Table 7: Cost calculation data base: 4 compressors, 5 vessels

Data input		
CAPEX		
LP Buffer	€	500.000
Pre-Compressor	€	2.200.000
MP Buffer	€	1.000.000
Control	€	200.000
OPEX		
Compressor Parts	% of Capex	2,5
Energy	€/kWh	0,04
Service	€/a	4.000
Technical parameters		
Duration	a	20
Power	kW	500
Operating hours	h/d	12
Capacity	kg/h	200
Economic parameters		
Interrest rate	%	2

In this variant, the costs of the filling plant contribute with around 0,4 €/kg to the hydrogen price. Assuming an 40% capex subsidy the contribute decreases to 0,3 €/kg

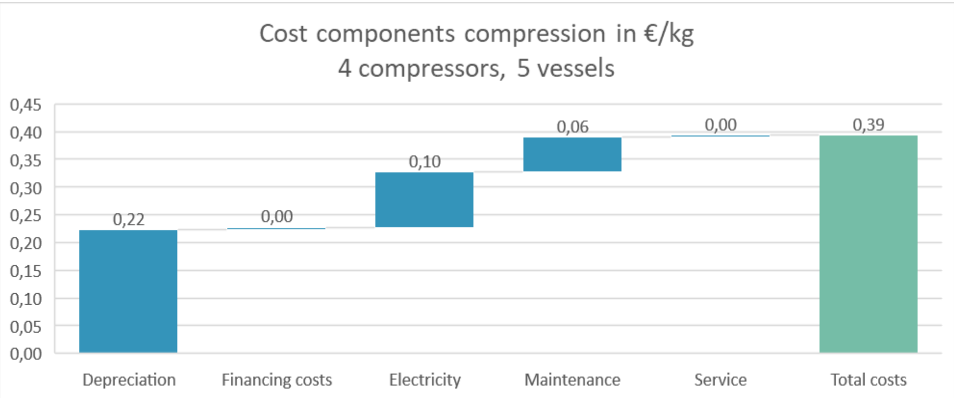


Figure 14: Influence of filling plant on H2 price; 4 compressors, 5 vessels

4.5 Hydrogen Storage Container

The technical details of containers were discussed in chapter 3.2. as well as the needed number of containers for different scenarios. The costs will be discussed below.

4.5.1 Container base costs

Some prices for 20 ft-containers were given above in Table 2. Figure 15 shows the price range in €/kgH2 based on personal information of different companies. It can be seen that the price is a function of container size and cylinder type used. 300 type 2-container are the cheapest ones, but they have a lower hydrogen capacity, so more containers are needed for the same hydrogen mass to transport. They only have 90 % capacity of 300 bar type 4/20 ft container and only 60% of a 500 bar container.

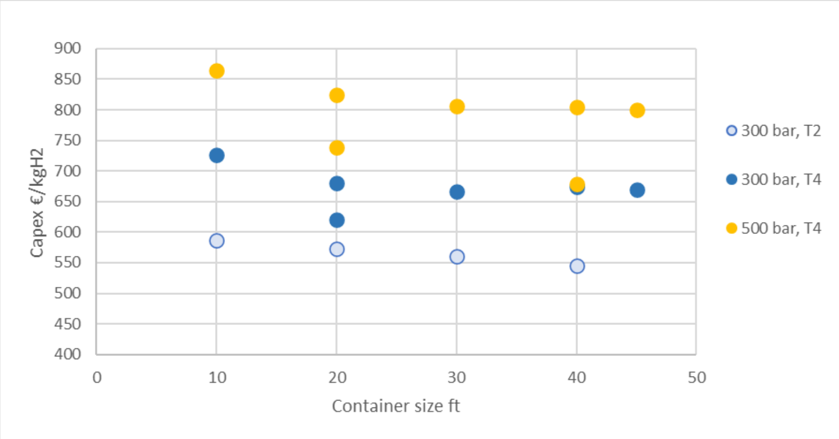


Figure 15: Range of investment costs for container

In chapter 3.2.2 the number of containers to operate one ship were mentioned. Table 8Table 1 shows the relating investment cost for the different container options.

Table 8: Investment for containers to operate one ship

Container Typ	Price estimation for one container	Number of containers needed	Investment
300 bar, T2	150.000 €	19	2,85 Mio€
300 bar, T4	230.000€	16	3,68 Mio€
500 bar, T4	380.000 €	12	4,56 Mio€

For the 300 bar, T2 variant are just 63% of the investment necessary in comparison to the 500 bar, T4 option, but for the upstream route there are 7 containers needed in opposite to 4 containers at 500 bar. That means more costs for storage place on bord as well as in the port or at the filling plant, more costs for transportation and lifting plus more time needed for handling the containers.

Some results of rough calculations regarding cost of container handling and storage are shown in Figure 16. Costs for one TEU were estimated based on data from different sources as follows: crane lifting 30 €/lift, material handling 25 €/handling, port storage 5 €/day and plant storage 2 €/day, and transport with truck 1,5 €/km [26–28]. It is assumed that the filling plant cannot be placed directly in the port and therefore a simple transport distance of 10 km is calculated. Two type 4-containers can be transported with one truck, for weight reasons this is not possible for the type 2-containers. Not included in the calculation are costs that can occur when handling the heavier T2 containers and the additional time for handling more containers. The yearly estimated costs for the 300 bar, type 4 container are 52% higher and for the 300 bar type 2 even 120% higher.

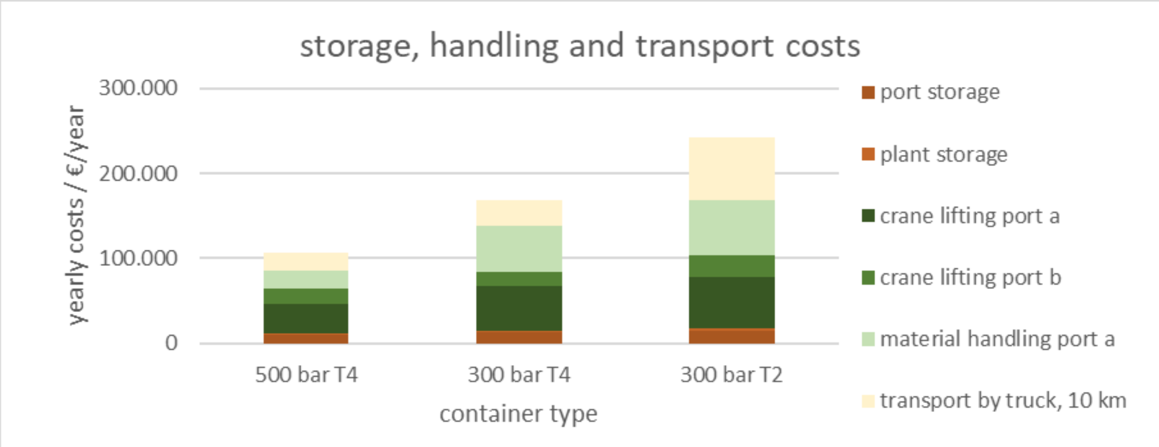


Figure 16: Yearly costs for storage, handling and transportation for number of containers needed on the Ro-Du-Ro roundtrip

In addition, the costs incurred during use on board must be considered. Due to the fuel containers, fewer freight containers can be transported. If the containers are not stackable, there are additional amounts for dead space. The costs were assumed with 140€/roundtrip based on an estimated price of about 40 to 50€ for one direction plus some bunker and congestion surcharges [29].

Figure 17 shows the most important costs for the use of the different container types based on an operating life of 10 years. In addition to the investment costs, the costs for the inspection due after 5 years are estimated at 10.000 €/container for the type4 storages. The handling, storage and transport costs were calculated for 10 years. The investment for the 500 bar type 4 containers is considerably higher than for the 300 bar type 2 containers, but this is relativized in the course of the years by the additional expenditure resulting from the higher number of containers.

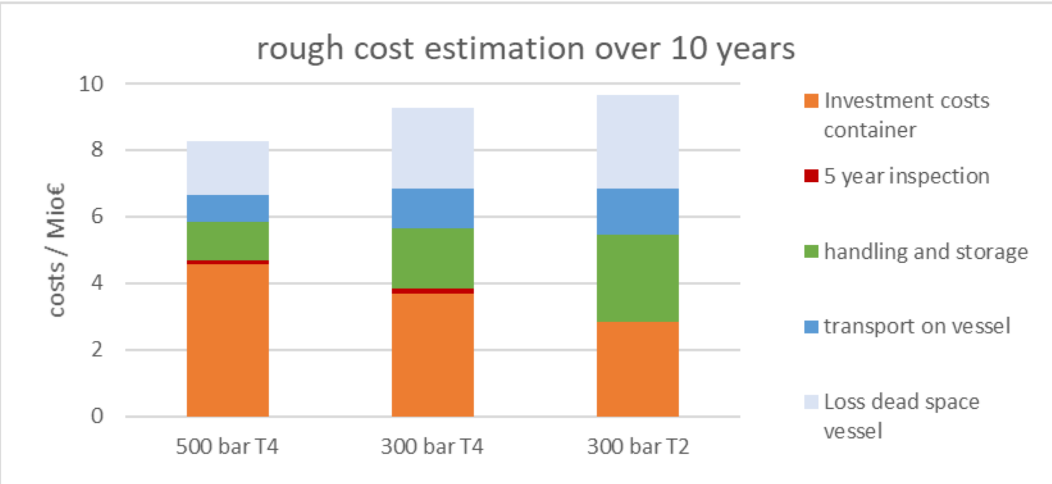


Figure 17: Rough cost estimation for different container options

These are rough estimations and not detailed cost discussions but they show clearly that not only the investment costs should influence the decision for a storage system. The follow-up costs are important as well.

It should be noted, that the above made estimations and calculations are based on the roundtrip Duisburg – Rotterdam – Duisburg with load profiles for a 135m container vessel. For other transport relations numbers of containers can be different and so results will be different as well! It is recommended to perform a live cycle costing (LCC) for concrete use cases.

4.5.2 Container rental costs

In conventional bunkering of ships, the tank is integrated into the ship, i.e. it is part of the ship and is added to the construction costs of the ship. Only the fuel is transferred from the bunkering point to the ship.

When swappable containers are used to store H2, the tank is no longer an integral part of the ship. During bunkering, the fuel is transferred with the storage tank, or the empty storage tank is removed. This raises the question of the ownership of the containers in such a system and how reliable fillings and the necessary logistics can be ensured. Furthermore, models for an economic operation have to be developed, in which both the investment costs and the operational costs have to be allocated.

The following parties can be considered as owners:

- The ship owner or operator.
  For a ship owner or ship operator, the procurement of H2 containers initially means a very high investment (see above). If an operation is carried out as described above, the owner would also receive third-party containers in the exchange. This raises questions about damage or age of the containers. This would not be attractive to individual participants or small fleets. For shipping companies with larger fleets, it is quite conceivable to invest in their own containers and use them only for their own fleet. In this case, the containers would have to be taken to appropriate filling facilities. The shipowner bears the investment and running costs for the containers and pays the pure hydrogen price.
- The hydrogen supplier/gas supplier
  For hydrogen suppliers/gas suppliers, an extension of the existing business model is possible. Here, the desired gas is delivered in cylinders or bundles. In addition to the cost of the gas, the customer incurs rental costs for the containers as well as transport or delivery costs. In the case of exchange containers, the gas supplier invests in production, filling equipment and the containers. The containers remain the property of the gas supplier. So, in addition to the pure hydrogen costs, a container rental fee as well as amounts for transportation and supply costs have to be paid in case of bunkering.
- Service provider
  Container distribution is also possible through independent service providers. The service provider owns the containers and rents them out accordingly. Hydrogen is either sourced lower value at low pressure after production and the value added of the filling is with the service provider or the higher value hydrogen is used after the filling plant. Transport and logistics are then the focus of the service provider. The bunker price is therefore made up of the purchase price for the hydrogen and, similar to the gas supplier, the rental price as well as the transport and supply costs.

If the storage system is not integrated on board of the ship, there are factors that need to be clarified. For a functioning exchange system, a defined standard must be set (see chapter

1.1.2.1). This standard must be adhered to by participants, regardless of who ultimately serves the different areas of the value chain. Quality assurance is also essential for both the containers and the hydrogen. Another point that must be considered is the handling of residual quantities. To ensure that enough fuel is loaded on the ship for the desired route, partially filled containers will often have to be exchanged for full containers. If, for example, a 20 ft, 500 bar container is still 60% full, this corresponds to approx. 300 kg of hydrogen at a price of, for example, 4 €/kg, which results in a value of 1200 €. This means that a procedure for determining the residual quantity must be established. At the same time, the filling systems must be able to handle corresponding residual quantities/pressures, especially when several containers are filled at the same time.

Regardless of the operator models, the main priority for the partikulier/shipowner is to ensure that standardized and thus interchangeable containers with consistently high hydrogen quality are available reliably and as inexpensively as possible at the bunker stations.

As discussed further above, there are different concepts for the ownership of the swap containers. On the one hand, the container might belong to the specific ship or the ship owner, on the other they would be owned by the hydrogen supplier. Both concepts have their pros and cons. In the first case, the ship owner has the choice who would refill his containers in the harbor. In the future, it could be for example that there are several suppliers (already today we have a number of H2 suppliers) who would support the bunkering of fuel cell ships. The ship owner could be sure that he always gets back “his” container which would also lead to a more careful treatment of the containers. Furthermore, it could be that the procurement of the containers could be eligible for funding together with the ship funding. However, there would still be a substantial amount of remaining costs for the investment into the containers (purchase price ca. 380.000 € multiplied by the number of ca. 6 containers/ship). The owner would also be responsible for the maintenance and periodic inspections which lead to further costs. If the container is filled by several parties, it could cause problems if a possible low gas quality would damage the fuel cell. Which suppliers would be made liable? In order to avoid such conflicts gas suppliers could insist on emptying the containers completely before refilling instead of just adding the consumed amount of hydrogen. This would also produce extra costs.

Taking all these disadvantages into account, a rental model is recommended for the swap containers. The containers would belong to the gas supplier. In order to avoid the quality and liability questions mentioned above, only the supplier would be allowed to refill his containers. It would not be necessary to empty the containers before, but just to add the consumed amount. The gas suppliers would also be responsible for maintenance and inspections. Being a part of the infrastructure, it is also not unlikely that the containers could also be funded with the erection of the filling station (which would have to be discussed with the funding agencies). As a cost compensation for investment and continuous costs for maintenance etc. the container owner would have to take a rental fee while the container is on board of the ship.

For the calculation of that fee two ideas are worth a further discussion: a daily fee or an add-on on the hydrogen price. For the daily fee we have calculated an investment of 380.000 € and a inspections/maintenance costs of 20.000 € over 15 years (the probable life time of the containers). These total 400.000 € have to be paid back during the 15 years. The uncertainty is to predict how long or often the containers will be rented (i.e. be on the ship). A careful assumption of 200 days/year would lead to 3.000 days in 15 years. This would lead to a minimum daily rental fee of 133 €/day. If the container would get a 40 % funding, the necessary minimum fee could be reduced to 83 €/day.

Another way of calculating the fee is to divide the whole investment and maintenance of all 54 containers (in the case of 5 ships), which is 21,6 Mio€, by the amount of hydrogen transported in the containers. One ship has three tours RO-DU-RO per week which need 2.800 kg H2/tour [30]. Assuming that this happens 48 weeks per years, a total amount of 30.2 tons of hydrogen will be consumed within 15 years. This would lead to an add on of 0,71 € on the kilogram price of hydrogen. If the containers would be eligible for a 40 % funding, the investment and maintenance cost would lower to 13,4 Mio€, reducing the add-on on the hydrogen price to 0,44 €/kg. However, also this method has uncertainties regarding the amount of H2 being consumed over the 15 years. Reductions in hydrogen consumption would require a higher add on to cover the depreciation of the container investment. It is impossible to predict at this point of time if lower consumption and higher H2 price compensate each other. Calculating a storage capacity of 500 kg H2 in a single container, this add-on would lead to 355 € respectively 220 € (depending on the really refilled amount of H2, as a container is never completely emptied for technical reasons). Comparing this to the model before, the daily fee (2 days tour duration x 133 €/d or 83 €/d) seems to be the cheaper model for the shipper. Maybe a mix of both models is a suitable solution. Anyway, the rental concept needs further discussions with the gas suppliers (as they also want to make a margin).

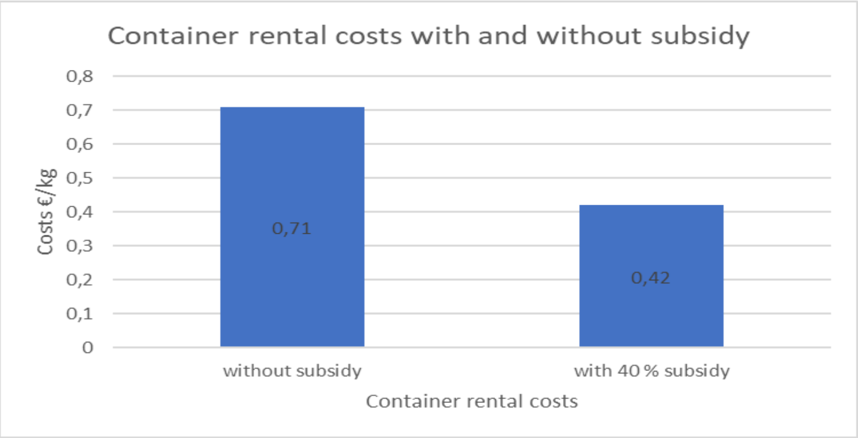


Figure 18: Container rental costs for 500 bar type 4 container

4.6 Accumulation of costs

Therefore, the interesting point is, how high will the hydrogen cost be if the above-mentioned parts of the infrastructure beginning with the hydrogen supply up to the container costs will be considered. Based on the assumption of operating 5 ships and a corresponding hydrogen demand and filling technology (4 compressors for the filling plant) the results of the calculations are shown in Figure 19 .

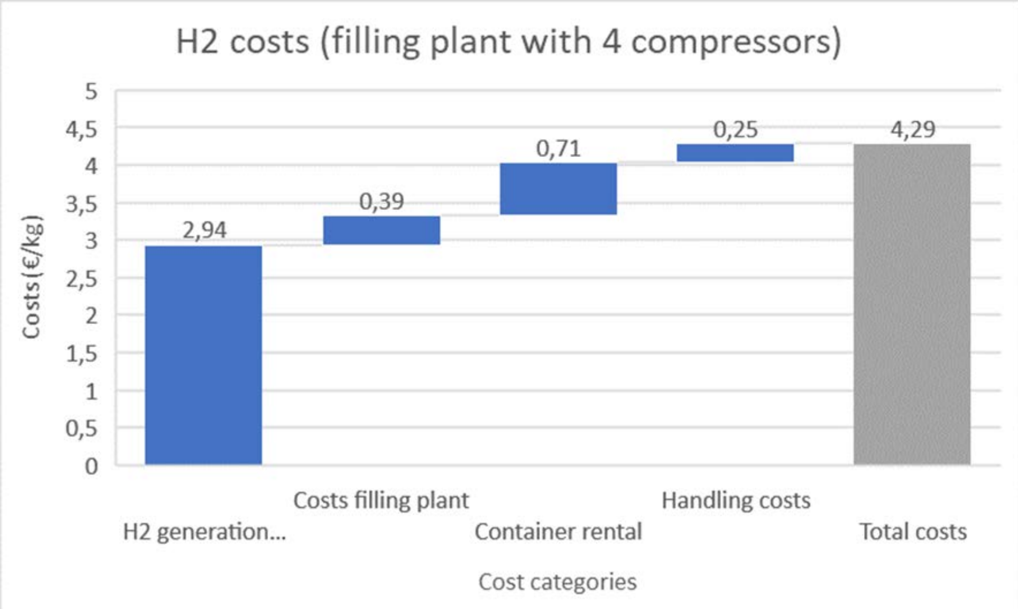


Figure 19: Accumulated hydrogen cost

For the second case we also assumed 5 ships and a corresponding hydrogen demand and filling technology (4 compressors for the filling plant), but also including a 40% capex subsidy.

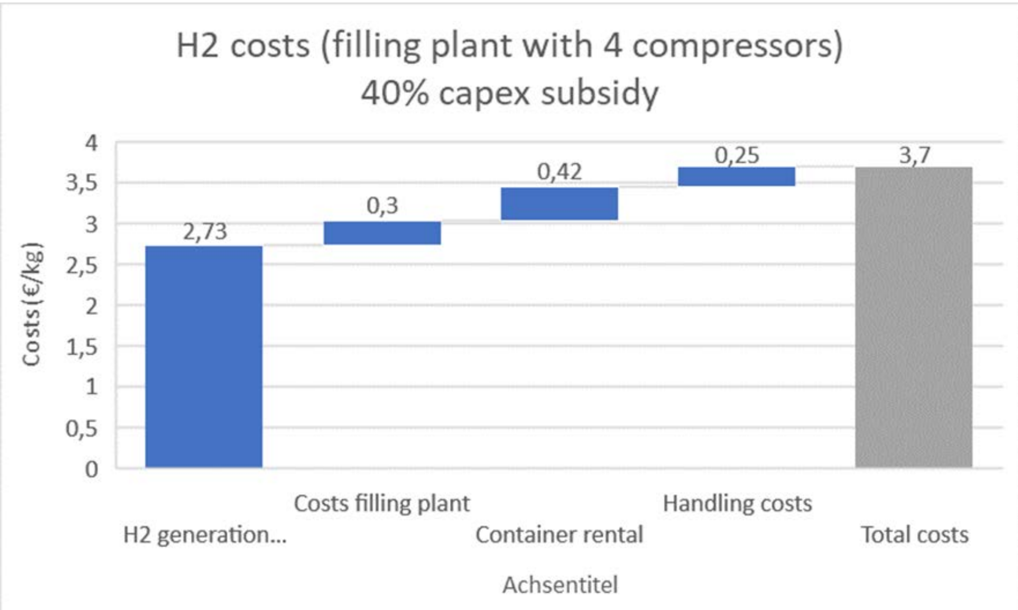


Figure 20: Accumulated hydrogen cost with 40% subsidy

If handling costs as mentioned above are considered as well (see Figure 16) about 25 ct/kg must be added to the accumulated costs. So, for the assumptions made hydrogen costs will be in a range between 3,70 €/kg and 4,30 €/kg without any margins, where generation costs have the highest share of more than 50% of the costs.

5 Identification of technological gaps

First of all, the bunker scenario with CH2 stored in containers will be analyzed. The main parts to be investigated are the containers themselves, the filling plant and the transportation of hydrogen storage containers. In a second step a rough overview of technical gaps for liquid hydrogen as energy carrier for inland navigation will be given.

5.1 Container

As described before CH2 transportation is sensibly carried out in MEGCs. Cylinders used here are typically type 4 cylinders or type 2 cylinders. The advantage of the type 4 cylinders is mainly the weight and the disadvantage are the costs. Technically there are no real gaps in here, but improvements in terms of weight and costs are desirable.

With the new standard EN17339:2020 as TPED approval higher pressures for type 4 vessels are permitted. Formerly 300 bar type IV cylinders can be filled up to 380 bar meaning an increase of 22% of hydrogen capacity and formerly 500 bar cylinders may be filled up to 640 bar a plus of 26% of hydrogen. Although the cylinders stay the same, piping and valves must be proven or renewed. This is not seen as technical gap, because in principle valves appropriate for high pressure hydrogen applications are available.

5.2 Transportation of containers

The transportation of containers is widely used everywhere in the logistics field. Containers can be transported by train, truck or ship and lifted by cranes, reach stackers, straddle carriers, side loaders etc. The main questions here are the weight of the containers and the regulations due to transporting pressurized and flammable gases.

Material handling devices are built to lift containers up to 45 t so transportation is mostly limited by the allowed total weight of trucks, which is in Germany and many European countries up to 40 t and 44t in combined transport.

As far as containers of a size of 20 ft are used, there will be no problem regarding weight. Type IV-Containers are listed with a maximum weight of about 15 t filled with hydrogen (NPROXX) and even type 2 containers for 300 bar are not heavier than 21,5 t. Due to the lower weight it is possible to transport 2 type 4 containers at the same time by truck. This does not work with type 2 containers.

5.3 Filling plant

The most complex and the less elaborated part of the bunker scenario with CH2 in MEGCs is the filling plant. Classical hydrogen filling plants are designed to fill Type 1 200 and 300 bar bottles and bundles. In contrast to that in a filling station for 500 bar containers there are higher pressures and larger amounts of gas to be filled and thus larger flow rates. Additionally, the type 4 cylinders have restrictions to maximum filling rates and temperatures. At the same time, rapid filling is desirable, especially from an economic point of view. Compliance with these restrictions must be ensured at all times by ensuring appropriate measurements and controls. Another point is the energetic optimization, which becomes more important because of the high amounts of hydrogen and the high pressures. Here, the whole concept from supply over buffer and compressors up to the container must be optimized.

The main components of a filling plant are shown in Figure 11 and described chapter 4.4. and will be discussed below with regard to technical gaps.

5.3.1 Hydrogen supply and gas treatment

For the hydrogen supply there exist different opportunities. Fossil fuel based hydrogen will be neglected so focus is on water electrolysis, the delivery via pipeline, cracking of ammonia or dehydrogenation of LOHC. The necessary drying or cleaning of the hydrogen gas, to ensure compressing and use in fuel cells without any problems, must be of a quality of 5.0 or compliant with the EN17124:2018 or ISO14687:2019 standard.

The most probable and technically advanced hydrogen supply method at present is water electrolysis. This is mature technic using different kinds of electrolysers, which will not be discussed here. Typically, condensers, pressure swing adsorption (PSA) or kinds of molecular sieves are used to purify the gas. Outlet pressures vary between 1 and 40 bar, where the upper pressure is preferable, so that buffering of the clean and dry gas can take place without any additional compression directly in buffers with pressure of around 40 bar.

Nowadays a discussion takes place to re-use pipelines for natural gas as hydrogen pipelines. This would enable the continuous transport of large quantities of hydrogen to different filling plants independently of the production site. The pipeline transport itself is not subject of this report, but the possible condition of the hydrogen affects the design of the filling station. Pressures in the range of 40 bar or higher would be desirable. The quality of the gas must be analyzed and appropriate purification processes such as PSA or combinations of membranes and PSA are required on site at the filling plant.

Another hydrogen supply method could be the cracking of ammonia. The last years showed an increasing interest in ammonia as ship fuel, as energy storage and fuel for power stations. The advantage of ammonia is that it is carbon free, the great experience from using it for many years in fertilizer industry and the easy and effective way of transportation. Ammonia is liquid below -33 °C at ambient pressure or at pressures over 9 bar at 20 °C. The cracking of ammonia is an endothermic reaction which can reach efficiencies of up to 90%. Up to now cracking especially with high conversion rates and high mass flows is not commercially used. For storing and using in fuel cells it must be ensured that no ammonia and nitrogen remains in the product gas, so purifying devices are necessary. Up to now pressures after cracker are in the range of 1 to 10 bar thus needing an additional compressor at filling station side. Further investigation and research are necessary for crackers in large scale and commercial applications.

LOHC (liquid organic hydrogen carriers) are mentioned as well as a source of hydrogen at filling plants and directly as fuel used on board of ships. The advantage of LOHC is the easy way of transportation and handling – without cooling or pressurizing - which is similarly to oil or diesel. To get hydrogen from the LOHC an endothermic reaction is necessary. For the release of 1 kg of H2, approx. one third of the energy content of hydrogen is necessary in form thermal energy. The product gas can be contaminated with traces of the oil thus a gas quality analysis and gas cleaning is necessary to prevent damage from buffers, compressors and fuel cells. Release pressure is 1 to 5 bar [31] thus needing a compressor for buffering. There are a few companies building LOHC storage and release units, but especially long-term stability and release process need more research and development.

5.3.2 Buffer

Some kind of buffer will be necessary to collect the dried and cleaned hydrogen at reasonable pressures of about 30 to 45 bar. For this buffers consisting of steel tubes with contents of up to 450 kg of hydrogen are widely used as well as 200 bar buffers with up to 600 kg of H2 capacity [21]. The buffers themselves are technical mature and there are no technical gaps, but the right dimensioning regarding energy optimization, investment and operation costs of the whole filling station is the challenge.

5.3.3 Compressors

One of the most important components of a filling plant is the compressor. Hydrogen compressors in different dimensions are state of the art. Piston compressors are preferable for applications with more frequent starts and stops. If a continuous operation is possible, membrane compressors are a good choice for hydrogen compression for high pressure working oil free and without leakages. Additional electro-chemical compressors are promising option for hydrogen compression. The challenge for compression lies in the right dimensioning to the estimation of the number of containers which must be filled per day or week and due the mass flows which will be allowed for filling. So not the compressor itself but the plant design is the challenge as mentioned before at the buffers.

5.3.4 Piping, valves, sensors

Hydrogen technology even with high pressures is approved for many years. Pipe materials, valves for different flow rates and pressures and sensors are available on the market. Nevertheless, some improvements for valves and sensors can support more efficient and easy operation of the filling plant.

5.3.5 Plant design

As described before the components of the filling plant are not the problem but the whole plant design including energetically, economically and safety regarding aspects are the real challenge. The hopefully growing hydrogen demand is a challenge for designing stations which are functional at the start of hydrogen economy with low demands and often standby operation and the opportunity to grow with the market.

At the beginning of the use of hydrogen on the Rhine, the focus will be on the purely functional filling of containers. I.e., rather slow but safe filling processes will be carried out, which, however, will enable a reliable use of the containers on ships. These first filling facilities should ideally be designed to provide a steady supply of H2 containers for the users, but also to serve as a research and development platform. In practical use, important knowledge can be gained for improvement with regard to both energetic and economic concepts. In addition to the pure design and tuning of the components, experience with the operating mode and control technology in particular promises optimization possibilities. Examples are the parallel and slow filling of several containers or the faster single filling. Factors such as compressor performance and corresponding energy consumption, investment costs, but also the limits for filling speeds are just some of the factors that have an influence on optimized filling. These findings can then be transferred to other filling stations that are necessary in the course of increased use of water. Setting up functioning plants is already working. Getting energetically and economically optimized filling stations for different hydrogen demand is the real challenge.

5.3.6 RCS

Regarding RCS the approval of the following components must be ensured:

- Cylinders must be approved for stationary and mobile applications, and this must be applied throughout Europe.
- MEGCs must be approved for stationary and mobile applications. The transport must be permitted on trucks, trains and ships throughout Europe. The use on ships must be allowed as well. If there is a special permission necessary for use at HRS it must be addressed as well.
- Standards must be set to guarantee an exchange of containers of different suppliers throughout Europe.

This subject is not discussed in detail with respect to the sub-study 1b [17].

5.4 LH2

In Europe exist currently only four LH2 plants with a total production of approx. 30 t/d (see chapter 0). Only the plant in Rotterdam with approx. 6 t/d hydrogen production is located directly at the Rhine. For all other plants, road or rail transport over several hundred kilometers would be necessary. LH2 pipelines do not exist. Inland vessels for the transport of larger quantities of LH2 are currently not available. There is still a need for development in this area. Additional LH2 production sites close to the Rhine would be important for an appropriate infrastructure.

According to DNV GL, "swappable" LH2 containers are currently not an option as a storage on a ship due to safety concerns. Thus, fixed IMO LH2 tanks would have to be used and refueling would have to be done by hose. Due to the lack of LH2 bunker stations, this would be done possibly by truck-to-ship bunkering. There is experience with this from the LNG sector.

From the current point of view, LH2 cannot be used as a fuel on inland vessels in the short term. If the infrastructure is further developed, e.g. by the heavy-duty sector and through corresponding safety-related developments and adjustments to the norms and standards, LH2 use is possible in the long term.

5.5 Technology Readiness Level TRL overview

As described in chapter 5 most of the components are state of the art, thus having a TRL of 9 based on the definitions of “HORIZON 2020 –WORK PROGRAMME 2014-2015” (see Appendix). Figure 21 shows an overview of the assessment of the whole chain from production to loading on the ship.

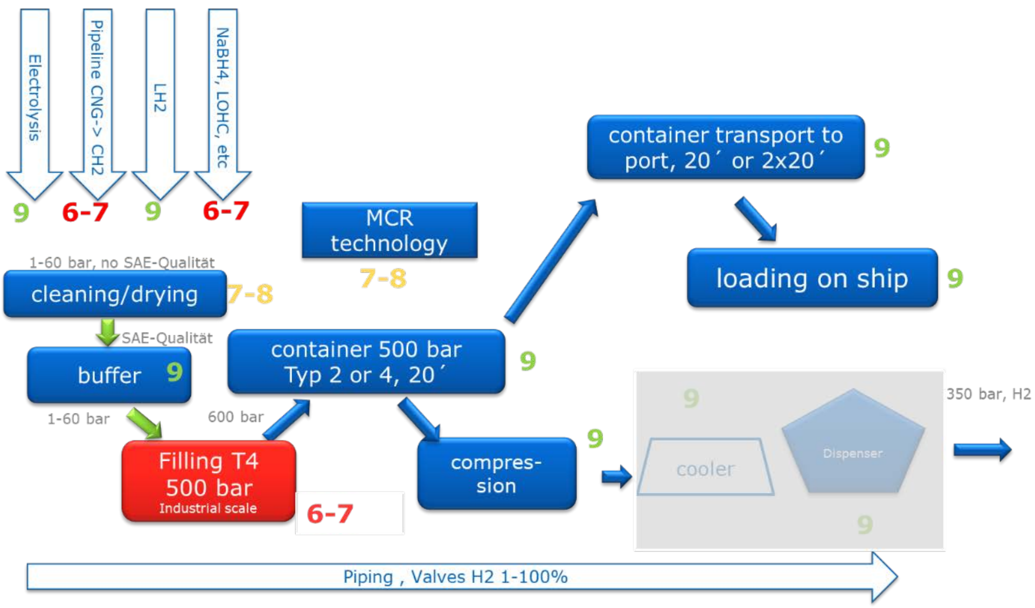


Figure 21: TRL for bunkering chain with CH2 container

All necessary components are available. The filling plant itself is marked with TRL 6 to 7, but this is only due to industrial scale. Filling of containers is possible today but it is far away from energetic, economic and process optimized ways. So, in principle from the technical side of view the infrastructure for a container based CH2 bunker scenario can be built immediately. By operating such a plant important experiences regarding operation and optimization can be made.

6 Detailed CBA for chosen bunkering scenarios

Cost-Benefit Analysis (CBA) is an analytical tool for judging the economic advantages or disadvantages of an investment decision by evaluating its costs and benefits in order to assess the welfare change attributed to an investment decision. This CBA-model looks at characterising the impact of the project regarding both the added value to society and costs. This assessment includes various society and cost-related indicators (KPIs: Key-Performance-Indicators). This chapter considers the concept of swappable hydrogen containers and the hydrogen generation costs describe in the chapters before.

In this analysis quantified societal costs of CO2 emissions and air pollutants such as particulate matter and nitrogen oxides were quantified. Different scenarios for the quantification of CO2 emissions are worked with. The different scenarios consider different time preference rates and thus weight the relationship between the welfare of current and future generations.

6.1 Assessment of the business model

Based on our own calculations [30], the energy requirement per rotation and fuel is listed. The route is assumed to be Rotterdam-Duisburg-Rotterdam. This can be divided into minimum, average and maximum energy demand. For the calculation the maximum energy requirement is used.

Table 9: Energy demand per rotation [30]

Route /Fuel	Unit	Ro-DU maximum	Du-Ro maximum	Total maximum
Diesel	l	11.594	3.865	15.459
H2	kg	2.060	687	2.746

We have taken the H2 costs from the previous calculations in this study and calculated an average price for diesel of 0,64 €/l in 2021 (January-April). Our assumption is 3 rotations per week with 48 weeks of operation. This results in 144 rotations per year. From this we have calculated the operating costs per year per ship (see graph below).

Table 10: Fuel costs per year per ship

Route /Fuel	Unit	Total maximum	Price (€/l resp. €/kg)	Operating costs per circulation	Circulations per year	Operating costs per year (1 ship)
Diesel	Diesel in l	**15.459**	0,64	**9.893,76**	144	**1.424.701,44 €**
H2 with small filling plant	H2 demand in kg	**2.746**	4,3	**11.807,80**	144	**1.700.323,20 €**
H2 with large filling plant	H2 demand in kg	**2.746**	4,29	**11.780,34**	144	**1.696.368,96 €**
H2 with large filling plant & 40% capex subsidy	H2 demand in kg	**2.746**	3,7	**10.160,20**	144	**1.463.068,80 €**

With this data, we have calculated the TCO per year for diesel and fuel cell vessel (with and without Capex funding). We assumed a large filling plant with 4 compressors. i.e. hydrogen prices at the lower level of 4,29 €/kg resp. 3,70€/kg (with 40% capex subsidy).

6.1.1 Diesel fueled vessel

For a diesel container ship we have assumed 1.5 million € as investment costs, divided into the hull (1.1 million €) and 400,000 € for the engine. The diesel price is an average price from 2021 (see previous chapter). For the hull we assume a depreciation time of 50 years, for the engine 15 years. For the full revision of the engine, we assume that this must be done after 8 years of operation so that this would occur once in the chosen observation period of 15 years.

Table 11: : Input data for cost calculations - diesel vessel

Data input			
CAPEX			Lifetime
Ship's hull	€	1.100.000	50
Engine	€	400.000	15
OPEX			
Engine maintenance		150.000	
Diesel	€/l	0,64	
Technical parameters			
Period considered	a	15	
Circulations per year	1/a	144	
Diesel consumption	l/circulation	15.459	
Economic parameters			
Interest rate	%	2	

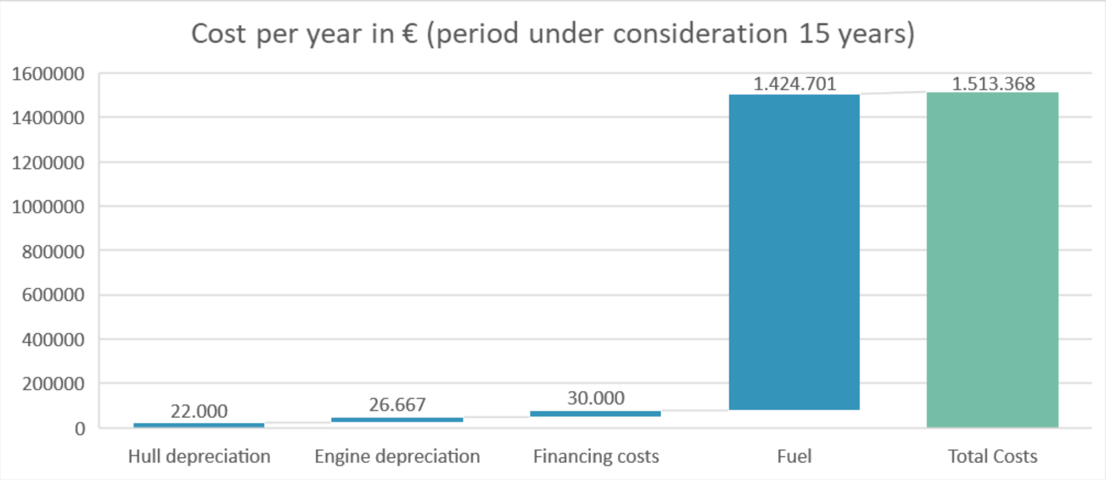


Figure 22: Costs for a Diesel vessel

With approximately 1,4 Mio€, fuel costs would account for a relatively high share (approx. 94%) of the total annual costs. The investment costs, on the other hand, would only have a small share in this.

6.1.2 Hydrogen fueled vessel

Costs for a fuel cell vessel with hydrogen from large filling plant, without subsidy

In this case, we have calculated the operation costs of fuel cell vessel with hydrogen (without Capex funding). We have assumed a filling plant with 4 compressors so that a demand of 5 ships can be covered. The price of hydrogen is thus 4,29 €/kg

For the investment in the hull, we assumed a depreciation period of 50 years. For the costs of the electrical system (400.000 €) and the fuel cell stack (1,5 Mio€) we have assumed a depreciation period of 15 years. In addition, we have assumed a replacement of the fuel cell stack in the amount of 60% of the capex after 8 years. The capex is not supported with subsidy. This includes the subsidy for the investment costs for the vessel as well as for the H2 production.

Table 12: Input data for cost calculations - H2 vessel without subsidy

Data input			
	CAPEX		Durability
Ship's hull	€	1.100.000	50
Electrical system	€	400.000	15
FC stack	€	1.500.000	15
	OPEX		
Maintenance FC stack	% of FC Capex	60%	
Hydrogen	€/kg	4,29	
	Technical parameters		
Period considered	a	15	
Circulations per year	1/a	144	
H2 consumption	kg/circulation	2746	
	Economic parameters		
Interest rate	%	2	

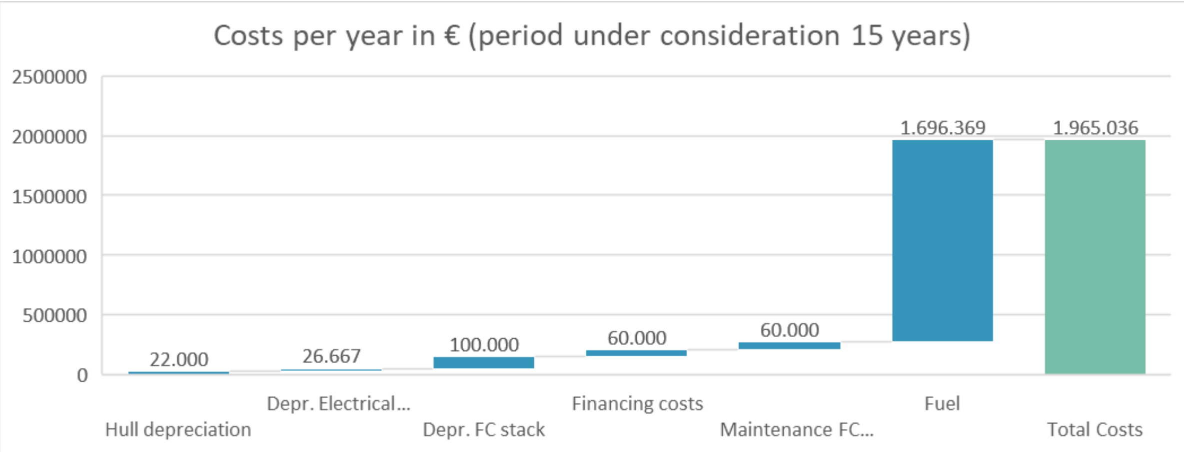


Figure 23: Costs H2 vessel per year without Capex subsidy

In this case, fuel costs being just under €1,7 million per year, are about 19% higher than for diesel. With a share of approx. 86% of the total costs, fuel costs again account for the largest share here.

Costs for a fuel cell vessel with hydrogen from large filling plant with 40 % capex subsidy

In this variant, we have calculated the costs for a fuel cell vessel with capex funding of 40%. This includes the investment costs for the ship as well as for the H2 production.

Table 13: Input data for cost calculations - H2 vessel with 40% subsidy

Data input			
CAPEX			Durability
Ship's hull	€	1.100.000	50
Electrical system	€	400.000	15
FC Stack	€	1.500.000	15
Capex subsidy		40%	
OPEX			
Maintenance FC stack	% of FC Capex	60%	
Hydrogen	€/kg	3,70	
Technical parameters			
Period considered	a	15	
Circulations per year	1/a	144	
H2 consumption	kg/circulation	2.746	
Economic parameters			
Interest rate	%	2	

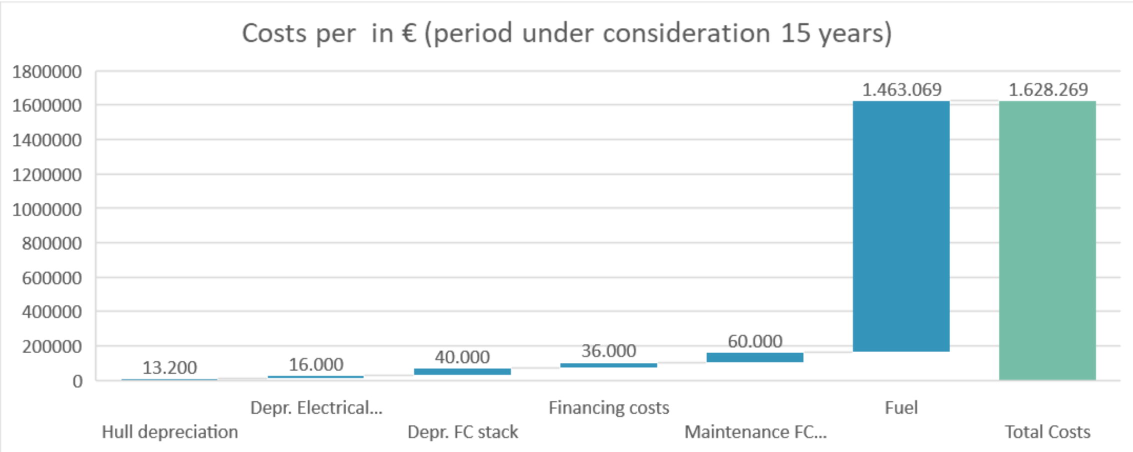


Figure 24: Costs H2 vessel per year, with 40% capex subsidy

Even in the variant with 40% Capex support, the fuel costs of just under €1.5 million make up the largest share and account for roughly 89 % of the total costs per year. Being slightly over 1.6 million € per year, the total costs per year are ca 8% higher than the costs of a diesel vessel.

6.2 Assessment of macroeconomic costs

In order to measure climate damage such as CO2 emissions, particulate matter and nitrogen oxides in monetary terms according to societal damage, we use the methodological approach of the German Federal Environment Agency (UBA) "Methodenkonvention 3.1 zur Ermittlung von Umweltkosten" (Methodological Convention for the Determination of Environmental Costs). [32].

The damage cost approach estimates the amount of damage caused to society by greenhouse gas emissions and the resulting climate change. The abatement cost approach, on the other hand, estimates the costs that society must bear if it wants to limit climate change to a certain target, i.e. avoid greenhouse gas emissions.

All cost sets of the Methodological Convention pursue the first-mentioned goal of determining the damages in monetary terms that society incurs due to environmental pollution. Conceptually, this corresponds to the damage cost approach, which is therefore used to determine the cost rates of the Methodological Convention, including the cost rates in the climate sector.

The cost rates presented in the following sections are based on the results of the research project „Methodenkonvention 3.0 - Weiterentwicklung und Erweiterung der Methodenkonvention zur Schätzung von Umweltkosten“ and UBA's own work [33]. The cost rates shown are average values for emissions in Germany, but their effect can also occur abroad. This applies in particular to damage caused by greenhouse gas emissions. Emissions of classical air pollutants and noise cause different costs depending on the emission situation.

6.2.1 CO2 emissions

UBA (Matthey/Bünger) 2020 [32] recommends the use of a cost rate of 195 €2020 / t CO2 eq for the year 2020 with a higher weighting of the welfare of current versus future generations and a cost rate of 680 €2020 / t CO2 eq with an equal weighting of the welfare of current and future generations. In addition, a sensitivity analysis with the respective other value is useful.

Table 14: UBA recommendation on climate costs in $€_{2020}$ / $t_{CO2\ eq}$ [32]

	Climate costs in $€_{2020}$ / $t_{CO2\ eq}$	
	2020	**2030**
1% pure time preference rate	195	215
0% pure time preference rate	680	700

6.2.2 Air pollutants

UBA's air quality modelling includes health effects, biodiversity loss, crop damage and material damage. Our calculations refer to average environmental costs of air pollution from emissions and focus on particulate matter and nitrogen oxides. The following table shows the average environmental costs per emitted ton of the respective pollutant for emissions from "unknown sources" in Germany. These average values can be used for a rough estimate of the damage costs caused by air pollutants if there is no specific information on the emission sources.

Table 15: Emission cost rates

Emissions	Cost rates for emissions in Germany €/t
PM2.5	61.500
PMcoarse	1.000
PM10	43.000
NOX	19.000

For particulate matter, the UBA has assumed that PM10 consists of 70% PM2.5 and 30% PMcoarse. We use an average of PM10 and PMcoarse 52.250 €/t PM emission.

6.2.3 Calculations of the macroeconomic costs

In this section we calculate the social costs of diesel in different scenarios. These take into account both the costs for CO_2 emissions and the costs for air pollutants (particulate matter and nitrogen oxides). The different scenarios take into account different time preference rates.

Scenario 1: Diesel, (1% pure time preference rate, 2020, 195€/$t_{CO2\ eq}$)

In this case we assume 1% pure time preference rate, which is the suggested UBA case. The use of a cost rate of 195$€_{2020}$/$t_{CO2\ eq}$ for the year 2020 implies a higher weighting of the welfare of today's compared to future generations.

Table 16: Input data for macroeconomic costs – diesel vessel, s1

Data input			
CAPEX			**Durability**
Ship's hull	€	1.100.000	50
Engine	€	400.000	15
OPEX			
Engine maintenance		150.000	
Diesel	€/kg	0,64	
Societal costs			
Costs CO2 emissions	€/kg	0,195	
Costs Nox	€/kg	19	
Costs PM	€/kg	52,25	
Technical parameters			
Period considered	a	15	
CO2 emissions per l diesel	kg/l	2,65	
Nox s per l diesel	kg/l	0,01764	
Pm per l diesel	kg/l	0,000147	
Circulations per year	1/a	144	
Diesel consumption	l/circulation	15.459	
Economic parameters			
Interest rate	%	2	

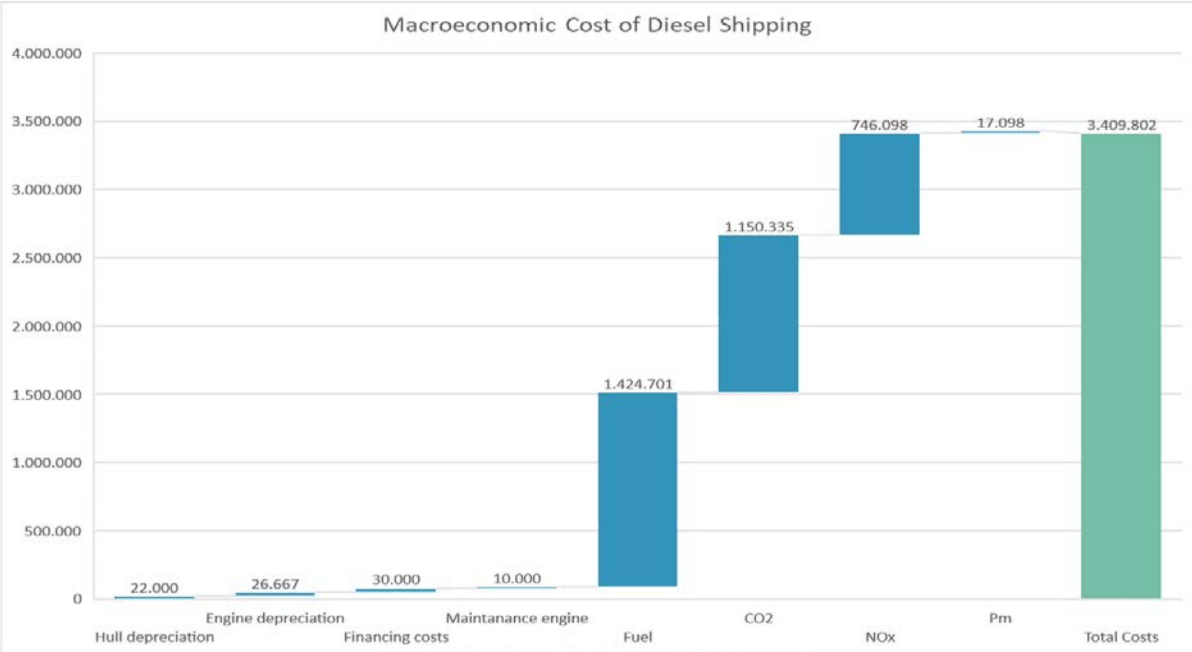


Figure 25: Macroecomomic costs of diesel shipping (Scenario 1: 1% time preference rate; 2020)

Taking into account the social costs such as CO2 emissions and air pollutants, the balance sheet for diesel is more than twice as high in this scenario, with costs of €3.4 million per year (cf. Chapter 4.2). Especially CO2 emissions (1.1 million €) and nitrogen oxides (almost 800,000 €) contribute by a large share to the increase in societal costs. The fuel cell-vessel variant would thus be socially advantageous even without Capex funding (approx. 1.5 million € less than the diesel in this scenario).

Scenario 2: Diesel, (0% pure time preference rate, 2020, 680€/$t_{CO2\ eq}$)

In this case we assume 0% pure time preference rate. The use of a cost rate of 860€ in 2020 / t CO2 eq for the year 2020 implies a higher weighting of the welfare of today's compared to future generations. The use of a cost rate of 680 $€_{2020}/t_{CO2\ eq}$ implies an equal weighting of the welfare of present and future generations.

Table 17 :Input data for macroeconomic costs – diesel vessel, s2

Data input			
CAPEX			Durability
Ship's hull	€	1100000	50
Engine	€	400.000	15
OPEX			
Engine maintenance		150000	
Diesel	€/kg	0,64	
Societal costs			
Costs CO2 emissions	€/kg	0,68	
Costs Nox	€/kg	19	
Costs PM	€/kg	52,25	
Technical parameters			

Period considered	a	15
CO2 emissions per l diesel	kg/l	2,65
Nox s per l diesel	kg/l	0,01764
Pm per l diesel	kg/l	0,000147
Circulations per year	1/a	144
Diesel consumption	l/circulation	15459
	Economic parameters	
Interst rate	%	2

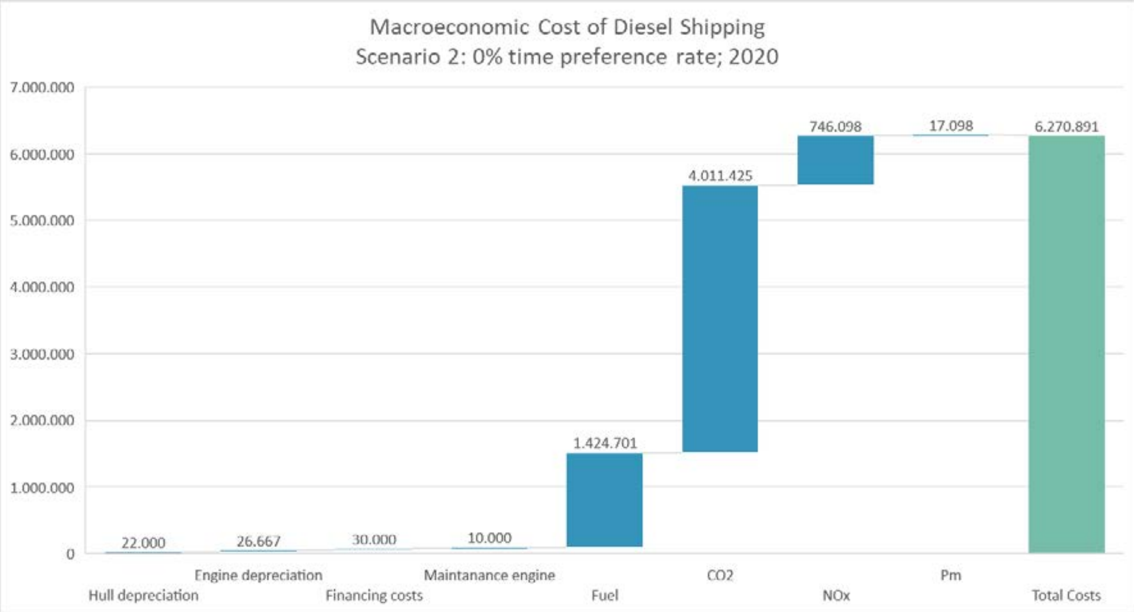


Figure 26: Macroeconomic costs of diesel shipping (Scenario 2: 1% time preference rate; 2020)

In Scenario 2, which implies an equal weighting of the welfare of current and future generations, the costs per year of €6.3 million are even significantly higher and increase fourfold compared to the use of diesel without taking the social costs into account. The use of fuel cell hydrogen technology in the amount of 2 million € per year (without Capex funding) would even result in a reduction in annual costs of almost 70%.

6.3 CBA Conclusions

Under today's conditions, the diesel variant is clearly economically advantageous compared to the fuel cell-hydrogen variant (approx. 29% additional costs for FC-H2). However, if a capex subsidy (e.g. 40%) is included, the latter variant comes closer to economic viability (approx. 8% additional costs). Since there is no mineral oil tax on marine diesel, the CO2 price has no effect in the economic model.

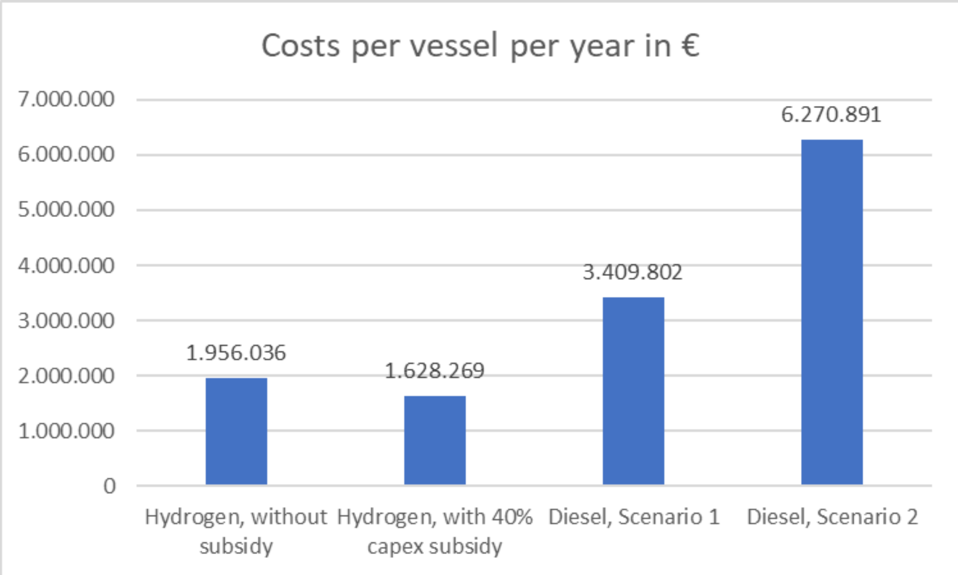


Figure 27: Macroeconomic costs of a diesel and a fuel cell hydrogen vessel

However, diesel causes high social costs, such as CO2 emissions and air pollutants (particulate matter and nitrogen oxides). The annual costs would more than double to 3,4 million €/year if the above-mentioned climate costs and a higher weighting of the welfare of current versus future generations (scenario recommended by the UBA, cf. Chapter 6.1.1, Scenario 1) are taken into account. The fuel cell-hydrogen variant would be strongly advantageous at just under 2 Mio€ even without capex funding. If one were to assume an equal weighting of the welfare of current and future generations (cf. Chapter 6.1.2, Scenario 2), the costs for the diesel variant would even rise to over 6 million € per year. The additional operating costs of 442.000€ for a FC vessel compared to a diesel vessel are contrasted by environmental cost avoidance potential of a ca. 1,5 Mio€. In the second scenario with equal weighting of present and future, the avoidance costs are even around € 4,3 million. The fuel cell hydrogen solution would be even more advantageous in this scenario. The development of a hydrogen infrastructure for ships could also lead to positive spill-over effects for the use of trucks or industrial uses near the port. However, these are difficult to quantify and were therefore not considered in this study.

7 HRS Blueprints

In addition to the technical aspects, the question of blueprints for filling stations must definitely be answered before the regulatory framework conditions. Here, the German conditions first play a role. Due to the strong influence of electricity costs on the total hydrogen production costs, this point has to be considered in particular. Due to the current revision of the regulatory framework, it is important to note here that there is a discussion ongoing that regulation for the maximum exemption of electricity costs for the production of green hydrogen by electrolysis is limited to 5000 full load hours. This leads to the fact that a design of the electrolysis capacity should be based on this number of hours. At the same time, it has to be taken into account that a ramp-up of the number of vessels should take place, which should not lead to the fact that the initial investments made are useless or have to be completely renewed.

These are some of the basic conditions under which the following considerations for a Blueprint were made. In addition, further boundary conditions, especially of a technical nature, must be considered:

- Consideration of the regulatory framework for minimizing electricity costs
- Utilization of the initial investment also in a larger expansion (modular design)
- Modular expansion concept for intermediate storage facilities and filling connections
- Concepts for capacity utilization especially in the build-up phase, therefore consideration of additional transport modes that could be supplied
- Strong variation of volume flow during filling of a container system (enlargement of buffer storage or power variation of the source)
- Consideration of segmentation of a container's storage (different pressure levels in the segments)
- Differentiation into a single-shift, two-shift and three-shift operation in filling
- Use of as many identical parts as possible in the structure (parallelization of modules)
- Avoidance of cooling during the filling of the containers by taking into account the maximum volume flows per individual tank

Under these conditions, the investigations of a blueprint to be carried out here are to be seen only as initial concepts. Since such plants have only been considered on this scale so far, it is absolutely necessary that a pilot plant is built first in order to be able to verify the theoretical considerations of this work package.

The planning assumes that a modular concept can be used, which can cover the medium scenario (5 ships).

The demand of maximum 1 t / d H2 in the larger and 0.5 t / d in the smaller filling plant for the scenario 1 ship could be covered by existing hydrogen production mostly meaning grey hydrogen. The more favorable option is to install an electrolyser powered by renewable energy. Assuming 65% efficiency, a minimum power of 2,2 MW would be required to supply 1 t/d of H2. Here, it makes sense to consider the next power level and design the available plant capacity for this, since larger electrolysers can produce the hydrogen more efficiently from an economic point of view. Therefore, it would be advisable to install more electrolysis capacity and find other use cases for the surplus hydrogen, e.g., for filling stations nearby or for chemical or steel production processes. A 500-bar filling system for type 4 tanks should be installed, consisting of a compressor with a minimum flow rate of 50 kg/h, some buffers with a capacity of 200 to 500 kg H2 at pressures of 40 bar, and perhaps at 200 bar, for example. The distributor must be able to fill at least 4 containers at the same time. Many processes will be manually controlled. The focus for the first hydrogen production and filling sites is. This filling plant will ideally also be a research platform to learn how the containers are filled. The different issues of a slow filling of parallel containers vs. a fast filling of a single container need to be investigated. With an arrangement of 2 parallel compressors, there is the possibility of continuous flow rate by dividing into different segments or containers inside. Thus, the possibility of the flow rate to compare stands with the source. In order to transfer the experience with the plant operation and to reduce the costs by common parts, the same plant sizes and construction for the two filling stations are suitable.

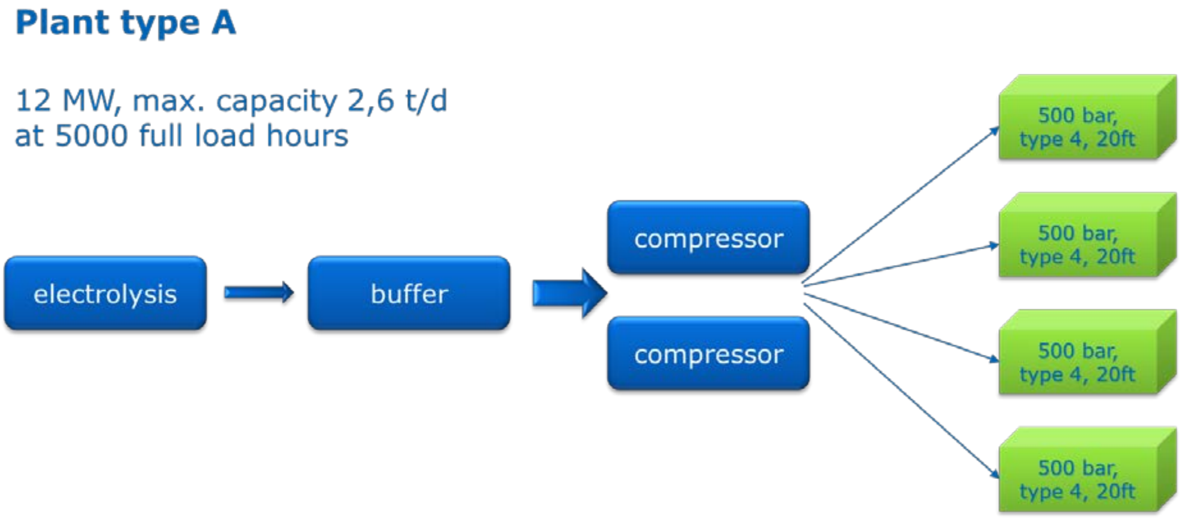


Figure 28: Scheme of filling plant prototype

The operation of 5 ships means a maximum of 5 t/d of H2 to be delivered at the larger filling plant. If hydrogen is to be produced on site by electrolysis, a theoretical minimum capacity of 11 MW (η=65%) would be required. The number or size of compressors must be increased to provide a minimum throughput of 210 kg/h H2. These values apply only if 24 h/d production and filling take place. Additional buffers must be installed and the manifold must be extended to fill more vessels in parallel. This can be done by an additional installation at the production site around another identical plant.

With this type of system, the required amount of hydrogen can be produced and filled in a first step in a single-shift operation, and there is sufficient reserve capacity to bridge initial problems with the system configuration. In the course of further expansion, an identical additional system can be installed at Site II, which will then provide the necessary output in a 2-shift operation. During the transitional phase of the ramp-up of the ships, a higher capacity of up to 2,6 t/d can be realized by operating the single system in two shifts. For this purpose, the number of containers must be continuously increased.

Thus, in the final configuration, three identical plants at two locations will be available for 5 ships. During the ramp-up phase, additional carriers can be supplied with hydrogen containers.

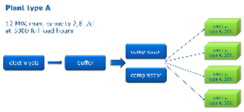
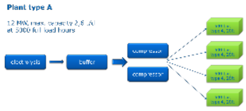
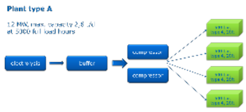
Site I		Site II	
Plant type A		Plant type A	
		Plant type A (as expansion)	

Figure 29: Expansion stage for 5 ships

In particular, the experience gained from container filling must be incorporated into suitable control strategies. Coordinated filling times and volume flows support an optimized energetic and economic design, be it through the buffer size or the compressor capacity. At least 54 containers are needed to operate 5 ships. Container filling and transport have to be coordinated. In this phase of the hydrogen ramp-up, concepts for container identification, location, data acquisition and recording have to be defined and tested.

In the third expansion stage with 100 ships refueled with hydrogen, whether with fuel cells or internal combustion engines, electrolysis only makes sense if the accompanying products (heat and oxygen) can also be marketed and sufficient green electricity is available. In total, there are then more than 750 containers in circulation. With two 2 filling plants, approx. 50 t/d have to be filled in the larger plant. With on-site production by electrolysis, this means a minimum output of 110 MW with 24-hour operation and an efficiency of 65%. Delivery by pipeline would be an interesting alternative at this stage, especially in view of the fact that other sectors such as land transport and steel production will also require high volumes of hydrogen. At the filling station, the number and capacity of compressors would have to ensure flow rates of at least 2,1 t/d. The filling station would have to be designed to fill at least 20 containers simultaneously. Splitting into parallel "filling lines" may be an option. The aim must be to optimize component sizes, functionality, energy consumption and economy. An additional advantage of such parallel filling lines is the minimization of downtime, since only parts of the plant would have to be shut down for maintenance or repair work. Moreover, these concepts could easily be transferred to smaller plants installed at locations that will be needed in the future, such as along the canal network or intermediate stations on the Rhine. 100 ships or more fueled by hydrogen is a medium-term (and hopefully not a long-term) scenario. In addition to CH2, LH2 may also be an option. Until then, existing container filling facilities can continue to be used, be it for shipping, be it to provide H2 at HRS or be it as intermediate storage for fluctuating renewables. Liquefaction is centralized (see Chapter 3.3) so production will be as well unless H2 will be delivered by pipeline. If liquid hydrogen can be stored in swap containers and used on ships, transportation and logistics would not be much different than for CH2. If this does not happen for safety and regulatory reasons, bunkering by hose is required, which will take longer than the container exchange. This will require new infrastructure to be built with bunker stations and/or bunker ships.

Overall, for the ramp-up of supply for ships, the module concept presented makes sense, but needs to be translated into real systems through appropriate initial projects, ideally deployed across transport modes. The exact design of the power quantities then results from the available module sizes of the electrolysis and the downstream compressor stages. In the case of a pilot plant, the plant should be accompanied by appropriate scientific research in order to shed light on the issues already mentioned. In addition to the technical design optimization, this includes in particular the optimization of the control of the entire plant and the economic mode of operation depending on the regulatory framework conditions.

8 Conclusion

The present „Design Study“ has examined the storage concept of using swappable containers for the hydrogen supply of inland waterway vessels on the Rhine River. The hydrogen is stored in gaseous form. The study shows that this concept is in principle feasible:

Assuming a storage pressure of 500 bar, the content of four 20 ft hydrogen containers is needed for the trip from Rotterdam to Duisburg. These containers are replaced in Duisburg by four full ones. For the trip to back to Rotterdam, roughly two containers are emptied which will then be replaced, so that for the tour to Duisburg again four full containers are on board of the ship. Such containers are already available today using either type 3 or type 4 tanks. About 500 kg H2 can be stored in such a container. This amount might even increase in the future due two newer regulations. In the case of 5 ships, it was shown that 5 tons of hydrogen must be produced and filled into the containers per day.

This hydrogen can be produced either at the harbor or at one of the existing hydrogen production plants. A production at the harbor would avoid transport costs. In the case of Duisburg, the necessary green electricity for the production by electrolysis could be delivered at costs of 4 ct/kWh. For the production of 5 t/d H2, a 12 MW electrolyser would be needed running at 8.000 full load hours. Hydrogen production costs mainly depend on the electricity price as the investment into the electrolyser can be depreciated over many years. It could be shown that H2 can be produced at 3 €/kg if no EEG levy is imposed. If EEG levy is imposed, the price increases up to 6,25 €/kg. Although for one ship a smaller electrolyser of 3 MW would be sufficient, it makes no sense to start with such as the number of ships will increase rapidly so that another electrolyser would have to be added, and larger electrolysers are also cheaper in terms of €/kW. The production costs of hydrogen by a 3 MW electrolyser would sum up to 3,3 €/kg. The production costs can decrease significantly if the investment can be funded. In Germany, electrolysers can be funded by 40 %. This would lower the production prices from 3,3 to 2,95 €/kg (3 MW, 1 ship) or 2,94 to 2,73 €/kg (12 MW, 5 ships).

For the refilling of the containers a refilling plant must also be installed. The CAPEX and OPEX of this plant lead to an increase of the hydrogen price in the range of 40 ct/kg in the case of 5 ships and 50 ct/kg in the case of 1 ship. Also in this case, a funding of 40 % is possible which would change the costs from 50 to 37 ct/kg (1 ship) or 40 to 30 ct/kg (5 ships) respectively. However, the eligibility of such a filling plant for funding must be discussed with the funding authorities.

A topic worth further discussion is the ownership of the swappable containers. They could belong to the ship and thus would be owned by the shipper, or they are owned by the hydrogen supplier. As such containers need regular maintenance and testing, the owner is responsible for that and thus has to bear the costs. As shippers have no experience with dealing with these topics, it seems to be more likely that the containers are owned by the hydrogen supplier. This has also the advantage that the supplier has the full responsibility for the quality of the delivered hydrogen and can be made liable for that if e.g., impurities lead to damages of the ship’s fuel cell.

Furthermore, such containers could then also be part of a larger hydrogen ecosystem. For instance, it is currently considered to use such containers also for the supply of hydrogen refueling stations (HRS) used for road transport. There, they would be used as semi-stationary hydrogen storages allowing a reduction of investment costs of such HRS as a stationary storage would no longer be required or could at least be smaller. Also, the necessary compressor could be of a smaller dimension leading to further reductions of the investment. In the case of the HRS supply the containers would be in the ownership of the gas supplier and not of the station owner. But the discussion about such concepts has just started. The outcome is not clear as someone has to invest into the containers. For a single gas supplier these investments would be enormous. But the more stations make use of this concepts, the more the investment would pay off and the containers would become much cheaper as well. With relation to the ship refueling, it would have to be examined if the ship containers and the HRS containers could be identical or if special regulations for the ship containers would apply so that the applications could not benefit from each other. This should be topic of further investigations and is not part of the present study.

The procurement and the operation of hydrogen vessels would lead to higher costs compared to Diesel vessels. On the other hand, the usage of hydrogen fuel cell vessels leads to significant reductions of the societal costs as harmful pollutants and climate gases are not emitted anymore. The societal costs of Diesel shipping are almost twice as high as of a fuel cell vessel, even without funding. But as the ship owner does not directly profit from these cost effects, his investment into the ship and also the operation of the ship should be subsidized substantially, in the latter case by subsidizing the hydrogen production making the H2 cheaper. With a 40 % funding, the costs per year would be ca. 100.000 € higher than with a Diesel vessel. This is still an economic challenge, but progress in fuel cell technology and larger H2 production capacities will lead to lower prices both for the ships and the hydrogen so that the gap between Diesel and hydrogen vessel will close in the coming years.

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9 Appendix

Definitions of the “HORIZON 2020 –WORK PROGRAMME 2014-2015”

TRL 1 – basic principles observed

TRL 2 – technology concept formulated

TRL 3 – experimental proof of concept

TRL 4 – technology validated in lab

TRL 5 – technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)

TRL 6 – technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies)

TRL 7 – system prototype demonstration in operational environment

TRL 8 – system complete and qualified

TRL 9 – actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space)