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Renewable Hydrogen Supply Scenarios for Inland Waterway Transport in Europe

Assessment of GHG Emissions and Costs

Elimar Frank[1*], and Luca Stauss[1]

[1] OST Ostschweizer Fachhochschule, Rapperswil, CH

*Correspondence: Elimar Frank, elimar.frank@ost.ch

Abstract. The European inland waterway transport needs to substitute 6.2 TWh of fossil diesel by renewable energy carriers. For hydrogen retrofit solutions investigated in the European project “Synergetics”, different Well-to-Tank pathways have been analysed to supply renewable hydrogen to Rotterdam, including buffer storage and fuelling to vessels. This paper compares two dominant scenarios with regards to GHG emissions and costs. One scenario is based on PV electricity from Morocco, transported to Rotterdam for electrolysis. The other scenario is calculated with electricity from offshore wind farms in the Northern Sea. The calculation of the PV scenario leads to specific emissions for the hydrogen supplied to vessels of 51 gCO_{2eq}/kWh_{H2} with levelized costs of hydrogen of 0.12 €/kWh_{H2}. The wind scenario led to 16 gCO_{2eq}/kWh_{H2} with 0.19 €/kWh_{H2}. The electrolysis has the highest impact on emissions and costs, especially the electricity demand. Accordingly, lower emissions of PV electricity supply would have a high influence on the overall results. On the other hand, for the low emission renewable hydrogen supply with wind power a further reduction of the costs of the installation will be relevant.

Keywords: Renewable Hydrogen, Well-to-Tank Assessment, Techno-Economic Analysis

1. Introduction

The European inland waterway transport sector uses about 6.2 TWh per year for propulsion, currently relying almost completely on fossil diesel, see Dahlke-Wallat et al. [1]. Most of the European inland waterway transport (IWT) takes place on the rivers Rhine and Danube (see CCNR [2]), using a variety of vessels with different specifications and operation profiles. Accordingly, few countries (The Netherlands and Germany with a share of the total ton-kilometres of about 37 % each, Romania about 9 %, Belgium about 6 %) are covering almost 90 % of the European IWT traffic. This is relevant for the challenges of local and global emissions and supply of necessary quantities of renewable energy carriers to reduce emissions in IWT in appropriate times and with the spatial distribution needed.

To achieve emission reduction aims (CO_{2eq}, but also NO_x, PM etc.) quickly, retrofit solutions are required due to long lifetimes of the vessels. For this, the EU project “Synergetics” analyses several options for renewable energy carriers with a multi-perspective approach.

Within the Synergetics project, combustion engines using hydrogen are considered as one of the retrofit options. For this, about the same quantity of energy used today by means of fossil diesel must be replaced by renewable hydrogen if considering a single technology pathway. In later studies, pathways for different renewable energy carriers might be combined.

Existing studies assess the environmental impact and costs of renewable hydrogen within different Well to Tank (WTT) value chains (e.g. Bothe et al. [3] and Liebich et al. [4]). However, usually key performance indicators (KPI) of the functional unit (e.g. gCO_{2eq} per kWh of a specific energy carrier) delivered to a generic location (e.g. central Germany) are calculated. Limited research is available on WTT studies specifically for the IWT sector and with regards to quantities, locations, and other requirements of IWT in Europe.

The core aim of this paper is to demonstrate the relevant environmental impacts and costs of renewable hydrogen WTT value chain scenarios tailored to meet the current energy demand of European IWT, i.e. replacing 6.2 TWh/a of fossil diesel by renewable hydrogen. Section 2 describes the methodology and section 3 focusses on the description of and results from two scenarios that have been selected from a study with 16 renewable hydrogen supply pathway scenarios.

2. Methodology

In this chapter basic model assumptions and calculation rationales are explained. The modelling is based on a modular approach, see **Figure 1**. Along the value chain, module categories have been defined which can contain different calculation modules representing specific technologies, e.g. for electricity production (PV = photovoltaic power plant, AWE = aquatic (offshore) wind power plant, OWE = onshore wind) or for the electrolysis (AEL = alkaline or PEM = proton exchange membrane). All modules have been defined and parametrized technically and economically. As key performance indicators, specific emissions (CO_{2eq}, NO_x, PM) and costs can be calculated including occurring losses in terms of energy and/or mass flows. **Figure 1** does not show all options, e.g. for the high voltage electricity transmission (the model distinguishes between overground, underground and sea cable). Also, some further but minor aspects are included in certain modules, e.g. water transport pipelines are part of the water treatment and supply module category.

The modules are connected to a scenario pathway by combining all in/outflows along a specific value chain. Selected specifications are given in Annex I: Background data. The modules are covering the Well-to-Tank perspective from a Well-to-Wake assessment, i.e. they start with the source of renewable energy and end with the energy carrier fuelling to the ship (bunkering). If a certain scenario does not contain one or more of the module categories (e.g. a hydrogen pipeline), the module category is omitted accordingly.

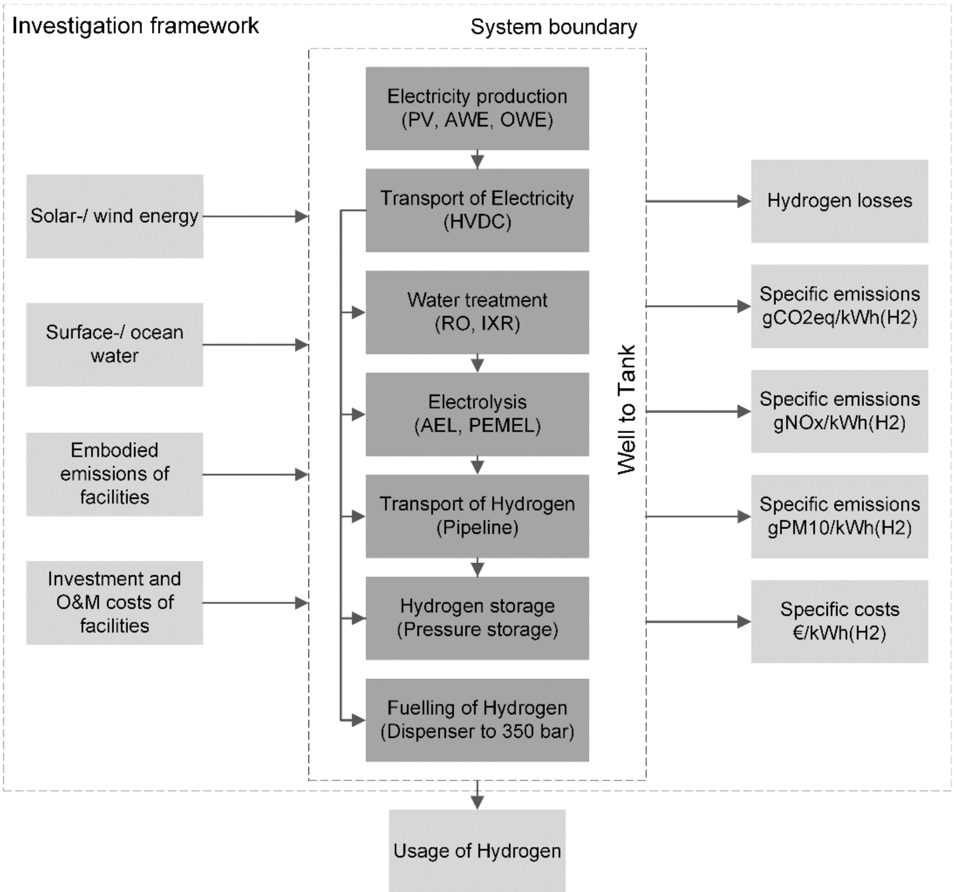

Figure 1. *Investigation framework including system boundaries and an overview on the module categories along the renewable hydrogen supply pathway value chain.*

For a full substitution of today's diesel demand for IWT in Europe by renewable hydrogen, we assumed that 6.2 TWh per year must be supplied to Rotterdam. In the retrofit solutions catalogue developed within the Synergetics project, direct combustion of hydrogen is considered instead of hydrogen fuel cells and therefore the amount of energy needed is about the same for using renewable hydrogen or diesel. Starting from the required output (fuelling/bunkering of 6.2 TWh of renewable hydrogen in Rotterdam) the model calculates backwards along the value chain which capacity the previous module (transport or production of hydrogen, treated water or electricity) must have to deliver the required quantity. Infrastructure and losses are considered. In a later extension, a more specific regional distribution from Rotterdam to the main IWT ports in Europe can be added which is currently assumed not to have a high influence on the overall results.

Two main groups of scenarios have been calculated: One using renewable electricity produced by large PV installations in Morocco and the other using either onshore or offshore wind turbines in the Northern Sea or coastal regions not far from Rotterdam, see **Figure 2**. For both groups. several variations and combinations in water treatment and supply, production of hydrogen at the PV plant or in Rotterdam, transmission of energy carriers, technology variations, etc.) have been carried out. For both main groups, in this paper only one representative scenario has been selected for a comparison and discussion of the most relevant aspects.

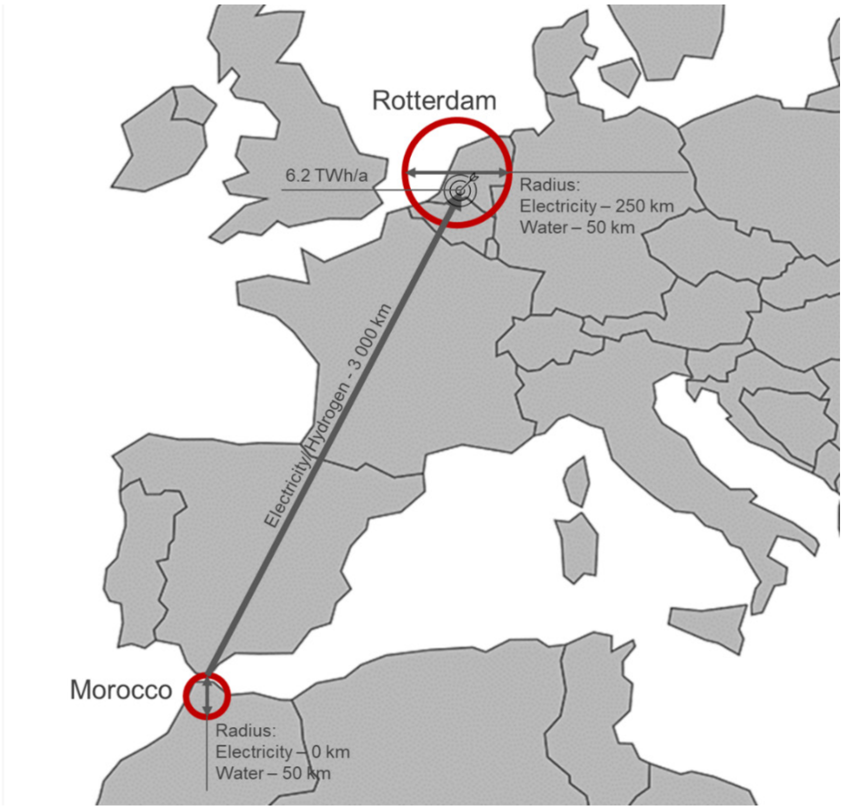

Figure 2. *Scenario boundary conditions and perimeters for energy and mass flow transports. Map taken from freeworldmaps.net with own additions.*

We calculated with renewable electricity only and assumed that we use electricity from the source modelled for all modules along the value chain. Since large quantities are required, we focus on water supply from ocean for the electrolysis to avoid interference with sweet water availability (also for locating the electrolysis in Rotterdam). Comparing with other scenarios, the difference between ocean and surface water treatment on specific emissions and costs per kWh hydrogen at the end of the modelled value chain showed no big difference. For the scenarios compared in this paper, we excluded onshore wind turbines due to limited free areas.

For transport infrastructure (e.g. hydrogen transport by pipelines or ships and electricity lines) we assumed that the infrastructure needed would not be solely built just for the annual 6.2 TWh of renewable hydrogen and the specific load profiles of the supply scenarios. Therefore, transport costs and emissions from larger installations have been used and transferred to specific costs and emissions for the energy carriers considered in this study.

The full load hours of the electrolysis equal the full load hours of the renewable electricity supply. Reducing the nominal power of the electrolysis would lead to higher full load hours and a more cost-effective operation of the electrolysis. However, this would lead to excess electricity production that would either have to be bought and not used (direct coupling) and would thus increase the costs for the single pathway concept calculation, or it would have to be assumed that the excess electricity from the scenarios calculated would be used by other parties (net coupling concept). In the latter case, it would not be clear anymore if and why the electrolysis would solely be operated with the renewable electricity supply potential calculated in the pathway. Also, it has been investigated if a reduced maximum power of the electrolysis for direct coupling would reduce the levelized costs of hydrogen production significantly. It was found that for two specific locations (PV in Morocco, wind offshore in the Northern Sea) and onsite electrolysis, based on hourly simulation and including a switch-on limit of the electrolysis at 10 % of the maximum power, the cost benefit when reducing the power of electrolysis relatively to the power of the renewable energy supply was neglectable.

3. Selected scenarios and results

From 16 scenarios calculated, this paper compares and discusses two representative value chain scenarios, one with low emissions and one with low costs:

- **Scenario #7**: Low total emissions (offshore wind electricity in the Northern Sea, sea cable electricity transport (250 km) to Rotterdam, ocean water desalination and transport of treated water (50 km) to Rotterdam, AEL)
- **Scenario #3**: Low total costs (PV in Morocco, HVDC-O = high voltage direct current electricity transport (3000 km) overground to Rotterdam, ocean water desalination and transport of treated water (50 km) to Rotterdam, AEL)

The two scenarios 3 and 7 serve as a good basis for comparison due to similarities: in both value chains, electricity is transported to Rotterdam and there used for alkaline electrolysis. Hydrogen storage and bunkering (fuelling) are also the same in both scenarios:

- In this paper low pressure (50 bar) gaseous hydrogen compression storage vessels (stainless steel) are considered since they are well-established for stationary storage applications, see Usman [5]. The storage capacity was calculated to store the amount of hydrogen required for one day's fuelling (510 tonnes) in order to serve as buffer between hydrogen production and hydrogen fuelling.
- For the fuelling station a pressure balancing facility with high pressure (500 bar) gaseous hydrogen compression storage vessels (steel and carbon fibre) is calculated before the dispensers. Hydrogen is compressed from 50 bar to 500 bar and then released through the dispenser in order to achieve a target pressure of 350 bar in the ship. The high-pressure storage capacity is assumed to store the amount of hydrogen required for half of a day's fuelling (255 tonnes).

Comparing scenario 3 with variations of value chains with electricity from PV in Morocco, the HVDC-O electricity transport turned out to be more cost-effective than hydrogen transport from Morocco to Rotterdam. At the same time, HVDC-O leads to higher emissions, see **Table 1**.

Table 1. *Costs and GHG emissions of energy transport from Morocco to Rotterdam by pipeline or high voltage DC overground cable, both for supplying the same quantity of hydrogen in Rotterdam. The GHG emissions include material and operation and hydrogen and electric energy losses.*

Energy transport Morocco – Rotterdam	**Hydrogen by pipeline**	**Electricity by HVDC-O**
Costs in €Cent/kWh$_{H2}$	6.5 (38 % of total)	1.6 (13 % of total)
GHG emissions in gCO$_{2eq}$/kWh$_{H2}$	3.4 (7 % of total)	7.8 (15 % of total)

Based on data from van Rossum et al. [6], the pipeline costs consist largely of facility costs. For a sufficiently large hydrogen pipeline (13 GW, see van Rossum [6]) over 3’000 km, costs due to pipeline facilities are 6.0 €Cent per kWh hydrogen where 12 % of the 6.0 €Cent result from the installation of the pipeline itself (investment costs of 0.215 €/(km*kW$_{H2}$) and O&M costs of 0.9 %invest/a) and 88 % result from compressor facility costs, calculated assuming one compressor every 100 km with investment costs of 34 €/(km*kW$_{el}$) and O&M costs of 1.7 %invest/a). Only 0.4 €Cent per kWh hydrogen come from the electricity demand for the compression and the remaining 0.1 €Cent per kWh hydrogen from hydrogen losses. The significantly higher GHG emissions of the electricity transmission (HVDC-O) in comparison to the pipeline comes from electric energy losses (4.5 gCO$_{2eq}$ per kWh of hydrogen at the end of the value chain) and the materials used, especially concrete and steel for high-voltage pylons (in total 3.3 gCO$_{2eq}$ per kWh of hydrogen). For a pipeline over the same distance, the GHG emissions can also be split into operation (electricity demand of compressors 1.9 gCO$_{2eq}$ per kWh of hydrogen, hydrogen losses 0.5 gCO_{2eq} per kWh_{H2}) and material (pipeline and compressors, together 1.0 gCO_{2eq} per kWh_{H2}).

For scenario 3, **Figure 3** shows the overview on energy and mass flows along the scenario pathway value chain. To supply and bunker the required 6.2 TWh of renewable hydrogen in Rotterdam, about 11.3 TWh of electricity are needed (PV in Morocco in case of scenario 3, with a peak power of 4.7 GW_p). Considering electricity transportation losses (HVDC-O, 3'000 km), a total of about 10 TWh of electricity are effectively used for the modules of the value chain located in the Rotterdam perimeter, with 93.2 % for electrolysis (nominal power 3.9 GW) and 5.0 % and 1.1 % for the compression of hydrogen for fuelling and buffering. The main techno-economic specifications for the calculations of modules used in the scenarios can be found in Annex I: Background data. It is important to note that the functional units vary. The most important results are related to the final output which is kWh of renewable hydrogen. These results are later summarized in **Figure 5** and **Figure 6**.

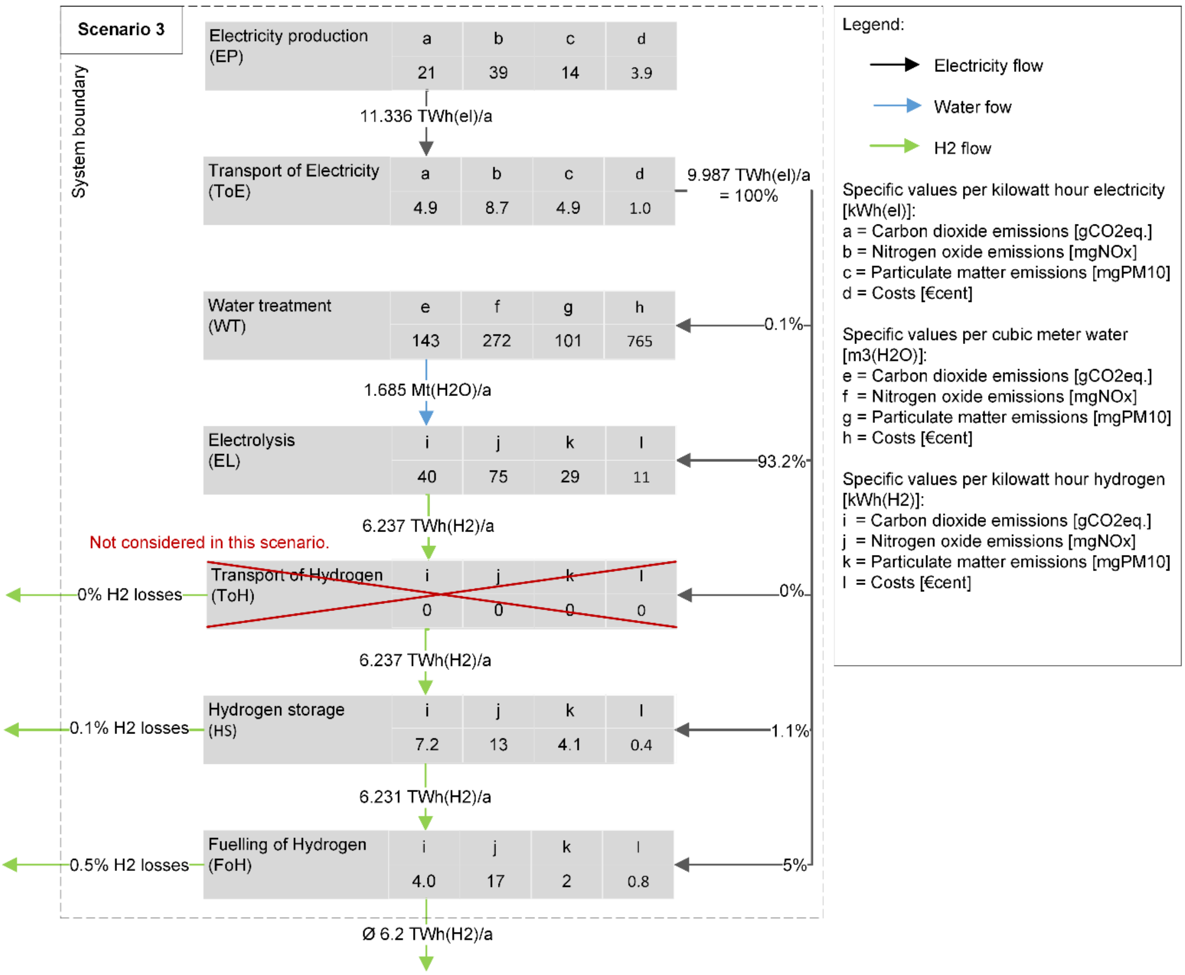

Figure 3. *Scenario 3 overview on energy and mass flows along the scenario pathway value chain.*

Similarly, **Figure 4** shows the overview on energy and mass flows along the scenario pathway value chain for scenario 7. Due to less losses for electricity transport, instead of about 11.3 TWh only about 10.0 TWh of renewable electricity supplied by offshore wind farms (nominal power of 2.7 GW) are needed, however, with deviating indicators (lower emissions, higher costs). The shares of the use of electricity in the subsequent modules is the same as in scenario 3, but all resulting indicators are different. The nominal power of the electrolyser is 2.5 GW in scenario 7.

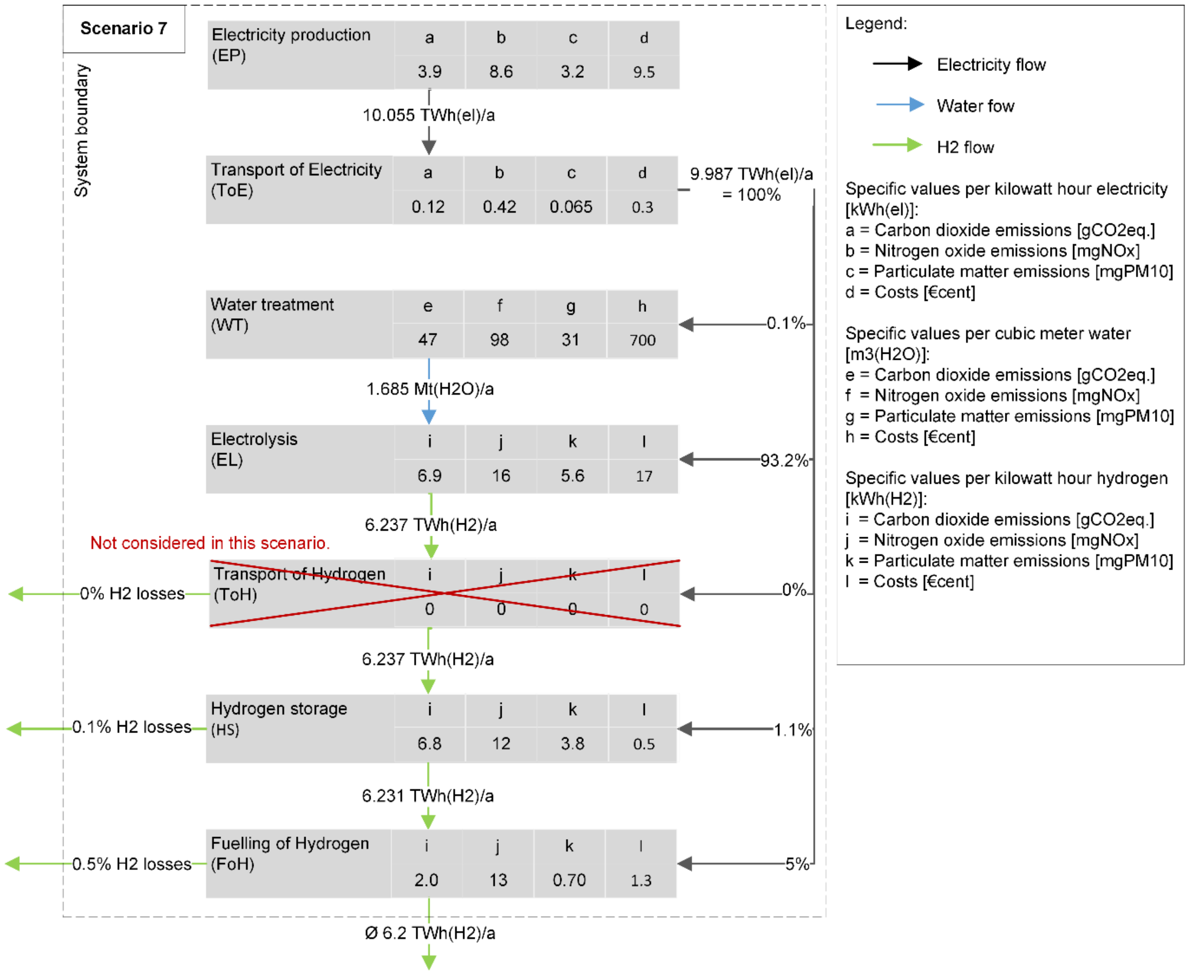

Figure 4. *Scenario 7 overview on energy and mass flows along the scenario pathway value chain.*

Figure 5 shows the total GHG emissions for hydrogen supply from renewable electricity production to hydrogen fuelled to vessels (Well to Tank) for both scenarios 3 and 7.

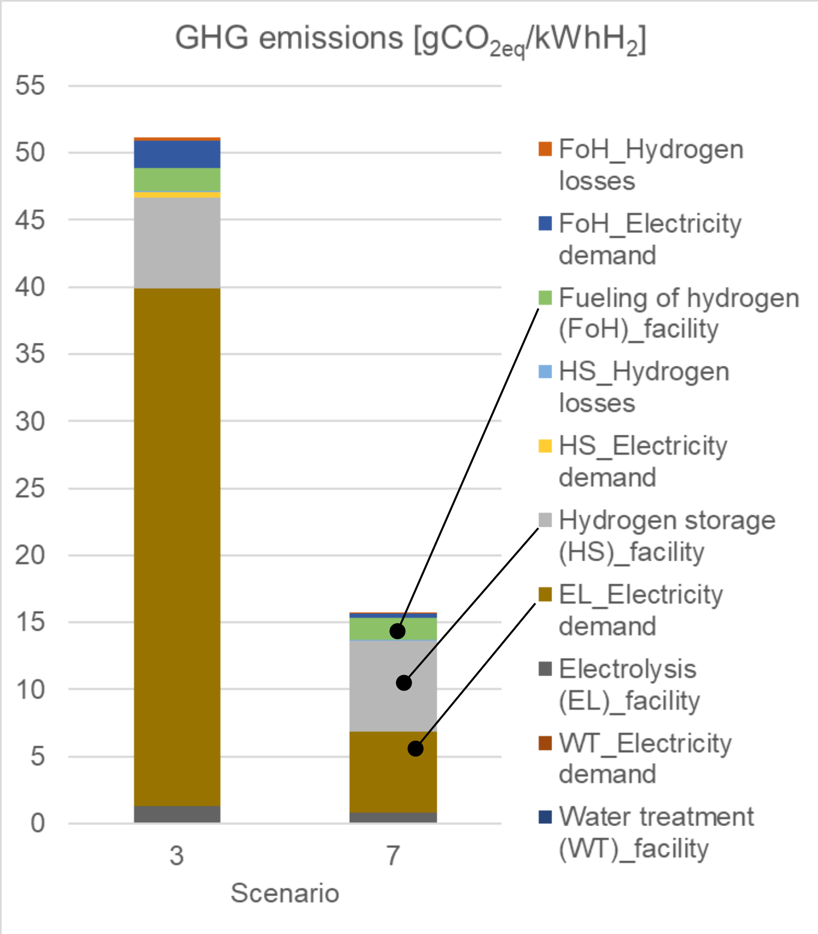

Figure 5. *Specific GHG emissions along the WTT value chains of scenarios 3 and 7, divided into the modules and further split up in embodied emissions of installations and operation-based emissions.*

In scenario 3 the total resulting specific GHG emissions along the WTT value chain are 51 gCO_{2eq}/kWh_{H2}, in scenario 7 they are 69 % lower (16 gCO_{2eq}/kWh_{H2}). These results are in the same order of magnitude as similarly orientated studies.

The three largest contributions are highlighted by arrows. In both scenarios, the electricity used for electrolysis has a high contribution (75 % of total in scenario 3, 38 % in scenario 7). The difference in the share is due to different emission factors of PV and wind. Also, a high contribution to GHG emissions comes from hydrogen storage (13 % and 43 %). The absolute contribution to the emissions is identical in both scenarios since it is related to the embodied emissions for the material needed for the storage (stainless steel for 50 bar storage pressure and a capacity of 510 tons). Only the emissions due to electricity demand and hydrogen losses vary between the scenarios. Another remarkable contribution comes from the fuelling of hydrogen (3 % and 11 %). Again, the absolute emission is identical (embodied emissions for steel and carbon fibre storage of 255 tons at 500 bar). These three major contributions sum up to 91 % of the total specific CO_{2eq} emissions per kWh of hydrogen in Scenario 3 and 92 % in Scenario 7, see **Table 2**.

Table 2. *Largest contributions to total GHG emissions in scenarios 3 and 7.*

Scenario	**% EL_Electricity demand** (EL = Electrolyser)	**% HS_facility** (HS = Hydrogen Storage)	**% FoH_facility** (FoH = Fuelling of Hydrogen)
3	75 %	13 %	3 %
7	38 %	43 %	11 %

In scenario 3, also the electricity demand for fuelling is worth mentioning. The difference to Scenario 3 can again be explained with the differing emission factors for PV electricity supply (Scenario 3) and offshore wind electricity (Scenario 7).

Water Treatment (including desalination) and transport to the electrolysis (50 km pipeline) is not relevant in both scenarios. Hydrogen storage losses have been assumed with xx and do not significantly contribute to the total specific emissions.

Figure 6 shows the total levelized costs for hydrogen supply from renewable electricity production to hydrogen fuelled to vessels (Well to Tank) for both scenarios 3 and 7.

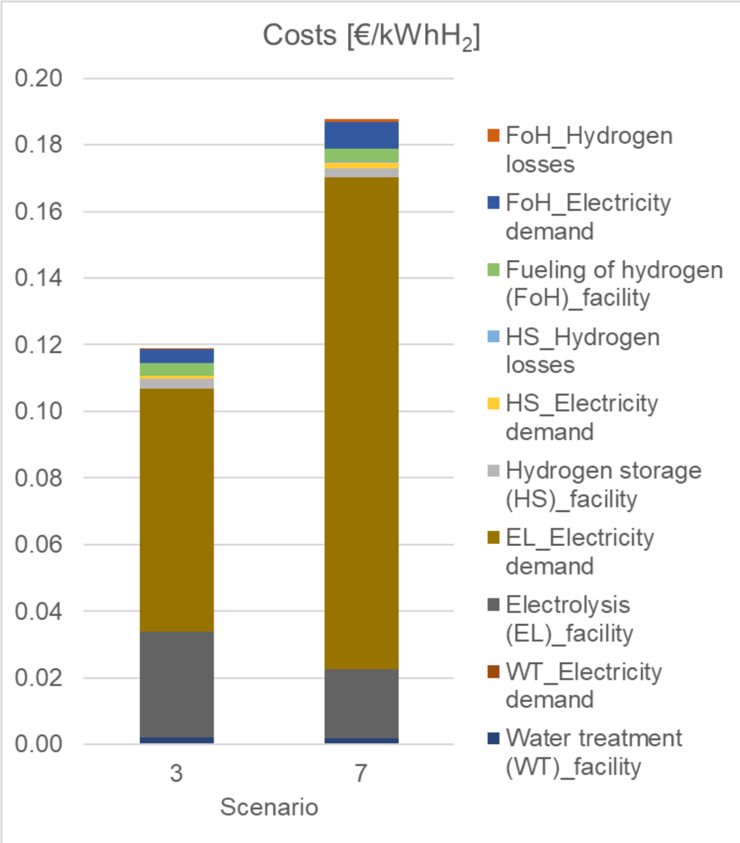

Figure 6. *Specific costs along the WTT value chains of scenarios 3 and 7, divided into the modules and further split up in embodied emissions of installations and operation-based emissions.*

In scenario 3 the total resulting specific costs along the WTT value chain are 0.12 €/kWh$_{H2}$, in scenario 7 they are 58 % higher (0.19 €/kWh$_{H2}$). Again, these results are in the same order of magnitude as similarly orientated studies.

As for the emissions, the electricity demand of the electrolysis has the highest contribution to the total levelized costs of the hydrogen delivered to the vessels. With higher specific PV production costs (0.039 €/kWh$_{el}$) compared to wind from offshore turbines in the Northern Sea (0.095 €/kWh$_{el}$), the electricity demand of electrolysis has the highest contribution (61 % in scenario 3 and 79 % in scenario 7). The second highest contribution is the electrolyser hard-ware with 27 % and 11 %, respectively, followed by the electricity demand for fuelling (3 % and 4 %). The three major contributions sum up to 91 % in scenario 3 and 94 % in scenario 7.

4. Discussion

In both scenarios, the electrolysis is highly relevant for the total specific GHG emissions and costs. With 26 gCO_{2eq} per kWh electricity for PV in Morocco plus transmission to Rotterdam, scenario 3 leads to more than 3 times higher specific GHG emissions per kWh of hydrogen fuelled to a vessel compared to scenario 7, where electricity from offshore wind plus transmission sum up to 4 gCO_{2eq} per kWh just for the supply of renewable electricity. Thus, future improvements of electrolysis will help to reduce remaining emissions and costs especially for scenarios based on PV electricity and long transport distances. Then, the lower costs compared to wind electricity may lead to increased relevance and attention paid to large quantity renewable electricity import scenarios. For today, the calculations presented provide indications of specific costs and GHG emissions for exclusive PV and wind scenarios.

Unlike in many other studies for the supply of renewable energy carriers, the paper includes an assessment of hydrogen storage and fuelling to vessels. The hydrogen storage sizes have a relevant impact on the GHG emissions due to the amount of material needed. For the costs, the fuelling of hydrogen has a recognizable influence, with both electricity demand and facility costs. For more detailed system analysis, the storage capacities needed should therefore be kept low.

Emissions and costs of water treatment have a marginal effect on the overall results (costs about 2 %, emissions 0.1 %). This allows flexibility in choosing water resources like ocean or surface water. However, the distance between the water source and electrolyser impacts treated water can increase the costs significantly which was calculated with a variation of the scenarios not presented in this paper. Hence, electrolyser placement close to water sources is important.

The model presented considers inputs for embodied emissions of the facilities as well as investment and O&M costs of the facilities. However, it does not reflect very detailed aspects such as the influence of process materials (e.g., catalysator materials, rare earths) or automatization and employee details (number of employees, country-specific wages, etc.). Also, the results presented are based on data suitable for the year 2020. However, cost reductions of the facilities as well as higher efficiencies due to more current data could lead to different results, mainly lower costs and emissions.

Renewable electricity transportation to several facilities has been simplified and summarized with a single transportation calculation. If a detailed electricity supply would be considered, costs and emissions can be expected to increase. Also, land use has not been included ecologically or economically. Other emissions (NO_x, PM) were taken into account, but have not been included in this paper since they are less relevant for hydrogen pathways.

5. Conclusions

The paper presents findings of Well to Tank pathways for the supply and bunkering of 6.2 TWh of renewable hydrogen to Rotterdam for the purpose of replacing fossil diesel in European inland waterway shipping. Significant quantities of renewable electricity have to be used. For this, production by large PV installations in Morocco and offshore wind farms in the Northern Sea have been calculated and electricity is transported to Rotterdam by HVDC transmission lines where the electrolysis, a hydrogen buffer storage and fuelling to vessels have been modelled. Water treatment including desalination has been assumed to be at the coast near Rotterdam with 50 km transport to the electrolyser.

Despite the long transport distance of 3000 km, the use of PV electricity from Morocco is significantly cheaper than the use of wind power from the Northern Sea (factor 0.6) but is associated with higher specific emissions (factor 3.2). However, political challenges must also be considered for this scenario, such as international contracts and the construction of transport capacities for electricity through various European countries. For the scenarios with PV electricity from Morocco, the detailed discussion of scenarios with a hydrogen pipeline was omitted in this paper because the pipeline would lead to higher overall costs with only slightly lower emissions.

Electrolysis is the most relevant part in the value chains of renewable hydrogen pathway scenarios. Assumptions regarding the improvement of both costs and emissions have a major influence on the overall result. However, these assumptions are linked to the question of the extent to which renewable hydrogen can be used in the transportation sector. As other sectors will also require renewable hydrogen and other renewable fuels may also be used in inland waterway shipping in addition to hydrogen, the results must be placed in an overall scenario. The "Synergetics" project is working on this.

With costs of 0.12 to 0.19 € per kWh of renewable hydrogen, both scenarios are significantly higher than the fossil diesel price for IWT in 2020 (about 0.05 €/kWh). Therefore, just for the energy carrier substitution concepts and strategies are needed to cover additional costs for the operators. Additionally, retrofit solutions will need financing schemes. These aspects are also investigated in the “Synergetics” project.

Author contributions

Elimar Frank: Lead in Conceptualization, Formal Analysis, Funding Acquisition, Investigation, Methodology, Project administration, Supervision and Writing. Minor contribution in Data curation, Validation and Visualization. **Luca Stauss**: Lead in Data curation and Investigation, Implementation of Methodology, Validation and Visualization, Assistance in Writing and Editing of the paper.

Competing interests

The authors declare that they have no competing interests.

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Annex I: Background data

Table 3. *Background data. Sources: Bothe et al. [3], Liebich et al. [4] and GEMIS [7].*

Technology		**Embodied CO_{2eq} emissions**	**Embodied NO_x emissions**	**Embodied PM10 emissions**	**Invest-ment costs**	**O&M costs**
	Unit	gCO_{2eq} per Unit	gNO_x per Unit	gPM10 per Unit	€ per Unit	% of invest/a
PV	kW	1‘500‘000	2‘800	1‘000	900	1.5
AWE	kW	360’000	800	300	2’800	3.2
HVDC-O	km*MW	240’000	400	350	140	1.0
HVDC-S	km*MW	135’000	500	60	975	1.0
RO/IXR-S,O	t_{H2O}/a	110	0.23	0.1	5.2	4.0
H_2O-Pipline	m	35’000	70	15	0.1 per t*km	-
AEL	kW_{el}	92’000	250	65	700	2.0
H_2-Storage	kg_{H2}	2’000’000	3’500	1’100	280	1.0
Compressor H_2 storage	kg_{H2}	63’000	130	60	25	7.0
Storage for dispenser	kg_{H2}	1’000’000	7’500	210	850	1.0
Compressor for dipenser	kg_{H2}	63’000	130	60	25	7.0
Dispenser	kg_{H2}/min	66’000	130	65	20’800	3.0