



D3.2 Study for H₂ transportation

HYMANTOVALLEY

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1. ABOUT THE DELIVERABLE

Deliverable 3.2, “Study for Hydrogen Transportation”, focuses on the techno-economic analysis of different hydrogen transport technologies, specifically within the context of the Hydrogen Valley in Mantova (HYMANTOVALLEY), which is the central focus of this project.

In particular, the study will evaluate various road transport solutions, including tube trailers operating at 250 bar, which is currently the most widely adopted solution, as well as innovative high-pressure alternatives at 500 bar.

Simultaneously, the use of liquefied hydrogen will be considered, offering the advantage of transporting volumes 3 to 4 times greater than compressed hydrogen at high pressure.

Finally, hydrogen transportation via pipelines will also be assessed.

The analysis will cover the entire hydrogen transport chain, from the initial compression or conversion of hydrogen for loading onto trucks or pipelines, to its final reconversion depending on the end-user. This includes applications such as power-to-power (P2P), power-to-heat (P2H), or hydrogen refuelling stations (HRS) at various operating pressures (for both heavy and light vehicles).

The techno-economic evaluation of these different transport options will be crucial for determining the preliminary feasibility and selecting the most suitable transport technology for the Mantova hydrogen valley. This selection will depend on the specific needs of the final user, with the goal of ensuring the most efficient and cost-effective hydrogen supply chain possible.

2. PROJECT OVERVIEW

This section introduces the HYMANTOVALLEY project, providing an overview of the specific task addressed in this document.

2.1. Project summary

The HYMANTOVALLEY project aims to demonstrate the decarbonization of one of Europe's most heavily air-polluted regions, located in Italy's Po Valley, by establishing a replicable green hydrogen ecosystem. This comprehensive ecosystem will integrate hydrogen production, storage, transportation, and utilization for multiple applications, including heat, power, and mobility. A key aspect of the project is the deployment of hydrogen-powered, zero-emission ships, trains, buses, and buildings, which are central to the region's transition to clean energy.

The project will develop an innovative hydrogen value chain, embedded within a unique tri-modal transport and logistics system that connects inland waterways, rail, and road. This system is strategically located near the Mediterranean and Scandinavian-Mediterranean corridors of the Trans-European Transport Network (TEN-T), positioning it at the heart of Italy's transport infrastructure. This integrated model will not only demonstrate the feasibility of hydrogen for decarbonization but will also be replicable in other regions.

HYMANTOVALLEY places a strong emphasis on engaging both local and European stakeholders, fostering synergies between industries and regional innovation ecosystems through knowledge exchange. By leveraging existing European hydrogen technologies, the project aims to stimulate broader collaboration in clean energy production and use.

In addition to the practical deployment of hydrogen technologies, the project will establish a European Centre of Applied Research and Advanced Training on Hydrogen, managed by leading universities. The centre will focus on optimizing and innovating across the hydrogen value chain, providing advanced training and applied research to support the commercialization and scale-up of hydrogen technologies.

The HYMANTOVALLEY project is driven by 14 partners and 2 affiliated entities from Austria, Belgium, Italy, and the Netherlands. It is co-financed by the European Innovation Council and SMEs Executive Agency (EISMEA), through the Interregional Innovation Investments (I3) Instrument, which is part of the European Regional Development Fund (ERDF). This funding aims to overcome regulatory barriers and enhance the investment readiness of interregional innovation projects.

Work Package 3 (WP3) focuses on the downstream activities of the hydrogen value chain, specifically targeting the distribution and end-use of hydrogen as an energy vector. This includes hydrogen delivery, transport, refuelling, and its applications across road, rail, and water transport sectors. WP3 also addresses critical aspects of security, authorization, and policy feedback, ensuring that regulatory frameworks support the successful deployment of hydrogen infrastructure.

Within WP3, Task 3.2 is dedicated to the study and definition of the optimal hydrogen transportation system. This task includes a detailed techno-economic analysis comparing different hydrogen transport solutions (compressed, liquefied, and pipeline) in terms of costs and performance across a range of use cases, including hydrogen refuelling stations (HRS), off-grid power generation, and public building heating.

2.2. Task Description and Objectives

The objective of this task is to perform a techno-economic evaluation (TEA) of hydrogen transportation solutions from the SAPIO production site in Mantova to various consumption points. The transportation methods under consideration include:

- Pipeline
- High-pressure tube trailers (500 and 250 bar)
- Liquid hydrogen (LH₂)

A preliminary model for the techno-economic analysis of these solutions has been developed in Python. This model currently evaluates hydrogen demand values ranging from 1 to 100 tons per day over transportation distances between 1 and 100 kilometres. All components of the various transport methods have been modelled using equations and cost functions, as described in detail in Chapter “4 Methodology”. These models were then implemented in Python to perform the sensitivity analysis. The analysis was conducted by varying the transport distance, hydrogen demand, and the pressure required by the end user.

The preliminary evaluation focuses on broad cost trends over large ranges to determine if certain transportation technologies are particularly advantageous for specific delivery distances and hydrogen demand volumes. Special attention is given to the requirements of end-users, such as the high pressures required for hydrogen refuelling stations (HRS).

Following this preliminary assessment, a more detailed analysis will be conducted, focusing specifically on the hydrogen valley of Mantova (HYMANTOVALLEY). Each technology will be analysed in relation to the different sub-processes necessary for hydrogen conversion, transportation, and final reconversion. A detailed analysis will be provided regarding the investment and operating costs for the optimal cases identified.

3. CASE STUDY

This section defines the case study of this work by outlining the various elements of the supply chain within the hydrogen valley of Mantova. The focus is on the types of transportation, end-user applications, and the specific locations of these components within the valley.

3.1. Identification of the H₂ valley (Supply Chain and Geographic Context)

This section provides an overview of the geographic, production, user, and transportation framework of the HYMANTOVALLEY project. The project focuses on developing a hydrogen valley where renewable hydrogen is produced, distributed, and utilized, centred around the industrial and port hub of Mantova.

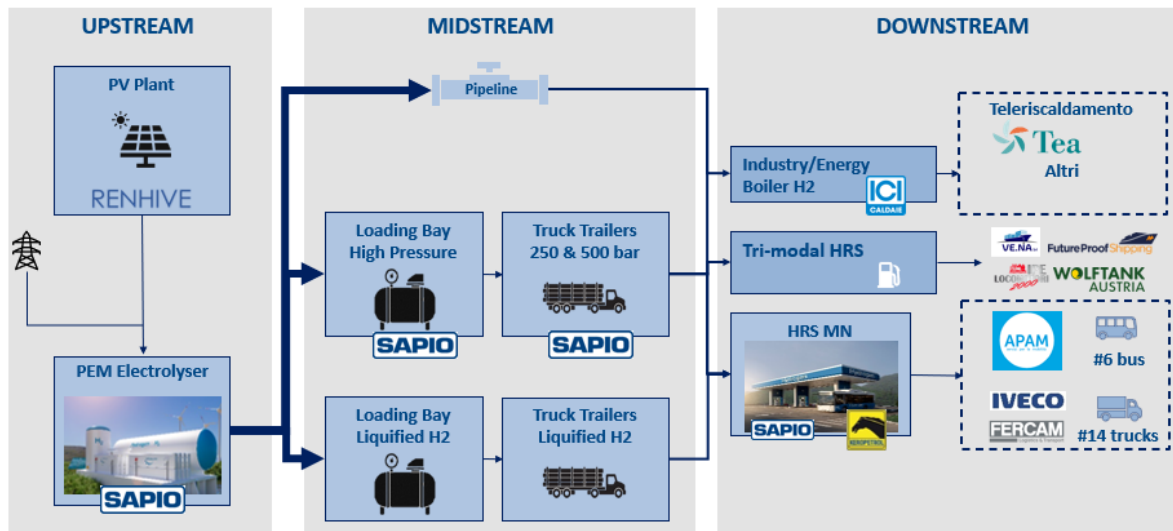


Figure 1: Hydrogen supply chain of HyMantovalley.

As shown in Figure 1, illustrates the complete hydrogen supply chain, consisting of the following key elements:

- **Renewable Energy Production:** The project integrates a 14 MW and a possible addition of 26 MW photovoltaic plant, paired with a 1 MWh lithium-ion storage system to ensure a steady supply of renewable energy for hydrogen production
- **Hydrogen Production:** Hydrogen is produced using a modular PEM electrolyser system with a total capacity of 10 MW (5 MW + 5 MW modules), aimed at generating approximately 1,500 tons/year of renewable hydrogen. The electrolyser is powered by the renewable energy produced by the solar PV systems, ensuring a green and sustainable hydrogen supply and a local battery energy storage.
- **Midstream - Hydrogen Distribution:** The produced hydrogen is distributed via two main transport technologies, plus an optional third one:
 - A dedicated hydrogen pipeline connecting the production site to various end-users.
 - High-pressure compression systems and tube trailers for road transportation, enabling hydrogen to be distributed flexibly across different sites.
 - Liquified hydrogen trailers

- **Downstream - Hydrogen Applications:** The renewable hydrogen produced is intended for a variety of industrial, transport, and energy applications:
 - **Industry Applications:** Partners like Versalis (heat-to-power) or Tea (heat-to-heat) will use hydrogen for industrial processes and others.
 - **Rail & Waterborne Refuelling:** Hydrogen refuelling stations (HRS) will support VENA, a hydrogen-powered tugboat, and the IPE locomotori hydrogen shunting locomotives, fostering clean energy solutions in rail and marine transport.
 - **Road Transport Refuelling:** A hydrogen refuelling station (HRS) will serve road vehicles, including 14 hydrogen-powered trucks from Iveco and Fercam, as well as 6 hydrogen-powered buses operated by APAM.

Going in detail in effective hydrogen chain that will be developed in this project, four/five primary hubs have been identified, and reported on the map below (Figure 2). These hubs represent critical points in the hydrogen production, distribution, and consumption processes of the valley's hydrogen supply chain.



Figure 2: Geographical layout of HYMANTOVALLEY

Precisely, the 4/5 key hubs can be identified as:

- **Hydrogen Production Zone:** This area is centred around the **SAPIO facility** in Mantova. The SAPIO plant will house a modular **PEM electrolyzer** system powered by renewable energy sources, primarily from a large photovoltaic installation. The electrolyzer has a total capacity of 10 MW, aiming to produce approximately 1,500 tons of green hydrogen per year, supporting local industrial processes, transportation needs, and heating applications.
- **Mantova Valdaro Port:** It acts as the natural terminal for the **Mantova-Adriatic inland waterway**, which extends 136 km. The port's strategic location, connected to the **A22 Brennero Highway**, positions it as a key node in the logistics network, particularly complementing traffic directed toward the **Quadrante Europa** in Verona. The port is fully equipped with cranes and other infrastructure to handle a variety of goods, including grains, coils, containers, and bulk materials. Additionally, its railway connection supports hydrogen distribution for maritime applications, making it a pivotal asset for hydrogen logistics in the region. For this reason, a tri-modal hydrogen refuelling station (HRS) will be located in the Valdaro port within the valley, supporting road, rail, and maritime applications. This station will play a critical role in enabling hydrogen-powered mobility across different transport sectors, serving hydrogen-powered trucks, buses, trains, and vessels such as the **VENA** hydrogen-powered tugboat.

- **Photovoltaic Park:** The energy needs of the hydrogen production process are met by a photovoltaic park that initially operates at 14 MW, with planned expansions to reach a total installed capacity of 40 MW. This renewable energy source is essential for maintaining the green credentials of the hydrogen valley, ensuring that hydrogen production is fully sustainable and zero-emission.
- **Industrial Hub:** The **Mantova Industrial Hub** is an essential component of the hydrogen valley, hosting several industrial users who will consume the hydrogen produced at the SAPIO facility. These users include **Versalis** for power generation and **Tea** for heating purposes. The close integration of industrial processes within the hydrogen ecosystem reduces the need for long-distance hydrogen transport, optimizing the supply chain for local consumption.

3.2. Production

The facility, owned by SAPIO, currently produces approximately 1,500 tons/year of hydrogen from a steam methane reforming (SMR) plant and will be complemented by a new modular PEM electrolyser with a total capacity of 10 MW (5+5 MW), aiming to produce an additional 1,500 tons/year. This electrolyser is partly financed through NextGenEU funds and partly through private investments.

The Hymantovalley (HMY) project will utilize renewable energy from a dedicated 14+26 MW photovoltaic (PV) plant, integrating a novel concept of energy stabilization through accumulators. This approach is necessary to maintain the electrolyser's constant 10 MW power input, while the PV plant's output fluctuates. The plants are being constructed with funds specifically allocated for the rehabilitation of abandoned industrial sites, thereby recovering land that would otherwise remain unused.

Three main options have been considered for energy stabilization:

- **1 MWh Traditional Lithium Battery:** This provides a comprehensive energy storage solution for time-shifting, backup during outages, and storage of excess energy. It is ideal in applications where weather conditions are unstable, offering consistent energy supply for time-shifting and backup during outages.
- **250 kW 100% Hydrogen Genset with CO₂ and Pollutant Removal (up to 8,000 hours per year):** This option offers clean energy generation with zero CO₂ emissions and highly efficient removal of pollutants such as NO_x and SO_x. It is suitable for off-grid applications, remote locations, or areas with unreliable grid access. This genset also provides environmental remediation while supporting various other scopes.
- **Hybrid Solution: 500 kWh Lithium Battery + 150 kW 100% Hydrogen Genset with CO₂ and Pollutant Removal:** This hybrid approach combines the benefits of both the battery and genset solutions, offering energy storage, clean power generation, and environmental protection. It provides an optimal balance between reliable energy storage and pollution-free power generation, making it versatile for different use cases.

3.3. Final utilizations

The end users have been categorized according to their different applications. Specifically, two types of end users have been identified:

1. **Industrial users:** for H₂ to heat applications, where the produced hydrogen will be used as a thermal source for various industrial processes, particularly in the following companies:
 - **Versalis:** a research and technological development center. Versalis is Eni's chemical subsidiary and a leader in the Italian chemical industry. It operates internationally in the sectors of basic chemicals, intermediates, plastics, and elastomers. The company is committed to renewable chemistry and the development of an integrated technological platform with a focus on circular economy.
 - **Tea:** a company likely involved in managing public services such as water, environment, and energy.
 - **Others**

This type of users has been simplified, it is assumed that hydrogen will be directly combusted to generate thermal energy, specifically for industrial furnaces and hydrogen condensing boilers.

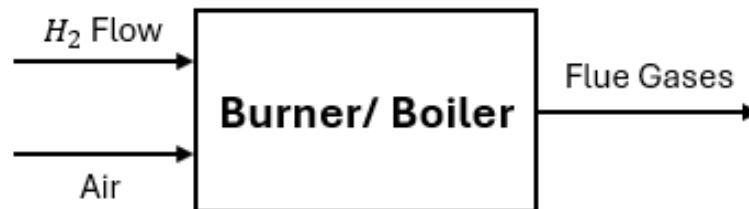


Figure 3: Burner/Boiler General simplification

These users have been modelled considering only the furnace or condensing boiler as shown in Figure 3, considering a required hydrogen delivery pressure of 10 bar.

2. **Hydrogen refuelling stations (HRS):** the Valdaro trimodal hydrogen refuelling station and the other possible Hydrogen refuelling stations are governed by the ISO 19880 standards, which provide comprehensive guidelines on the design, construction, operation, and maintenance. Different kinds of Hydrogen stations exist. In this project, we focus only on external hydrogen supply stations with gaseous or liquid hydrogen delivery, which is the most common HRS worldwide. HRS based on gaseous hydrogen delivery can be schematized by the following components, reported in the Figure 4:
 - Connection cabinet for unloading (C.C.)
 - Low pressure hydrogen storage (Compressed H₂)
 - Compressor unit: typically, mechanical booster of diaphragm compressors usually operates in the 70-95 MPa range, under 135 °C^{1,2}.
 - High pressure storage (Buffer HP): in the 70-95 MPa range
 - Precooling unit: fundamental to pre-cool compressed hydrogen, decreasing its temperature of -20 to -40 °C to respect the 85 °C operating temperature limits for vehicles hydrogen storage system.
 - Hydrogen dispenser

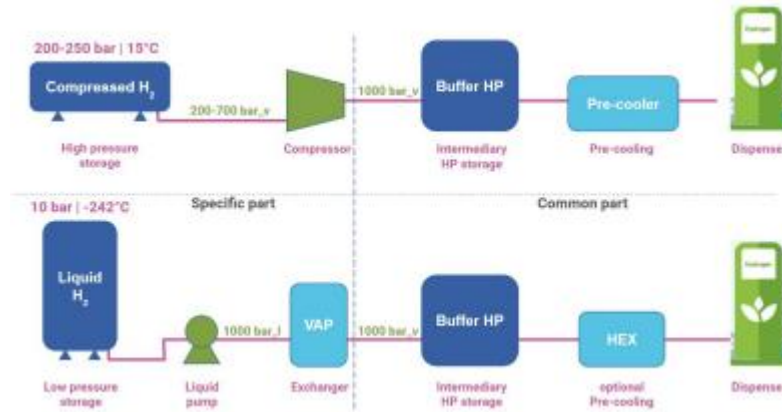


Figure 4: General HRS layout form gaseous and liquified hydrogen³

For the HRS has been considered also the option of liquified hydrogen delivery by truck trailers due to the high storage capacity of these systems. The hydrogen refuelling stations based on LH₂ storage have a similar layout to the gaseous one the specific generalized components as³:

- LH₂ tank: (around 20 m³ - 1000 kg_{H2}) with a maximal operating pressure of 10.3 bar
- Liquid Pump: an insulated process line from the bottom of the storage to the LH₂ pump, driving LH₂ from the storage tank to a vaporizer; this device allows to pump LH₂ up to 1000 bar
- Heat Exchanger for vaporization (VAP): hot oil, electric to heat up hydrogen up to 1000 bar

All the other parts (e.g. dispenser, filling hose...) of the refuelling station are like classical gaseous refuelling station.

For the need of the specific tea analysis have not been considered the total costs for the hydrogen refuelling stations in the levelized cost of transport, but only the additional costs related to the use of different transport technologies (CH₂ and LH₂) and different pressure required for heavy vehicles requirements (350 bar tanks) and light vehicles ones (700 bar).

The modelled components for HRS based on compressed hydrogen delivery will be:

- Compression unit from hydrogen trailer specific pressure to the end user one

The modelled components for HRS based on liquified hydrogen delivery will be:

- Cryogenic pump unit from hydrogen trailer specific pressure to the end user one
- Evaporator unit for regassification of liquified hydrogen (heater).

3.4. Selected transportation technologies

Various hydrogen transportation solutions are considered based on the specific quantities and distances needed to connect producers and consumers. These two factors significantly influence the choice of transportation method, as minimizing the levelized cost of transport (LCOT) of hydrogen is essential. Truck transport of compressed gaseous or cryogenic liquid hydrogen can move smaller quantities (1 to 4 tons of H₂ per truck), but the per-kilometre cost per kilogram of hydrogen is substantial, limiting its viability as a heating fuel. Pure hydrogen pipelines seem to offer the most promising solution for large-scale, low-cost deployment of hydrogen as a zero-emission fuel. Pipeline transport is an effective method for connecting centralized or distributed production sites directly to customers. Figure 5 from IRENA's report, *Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Part II*⁴, illustrates optimal transport solutions based on varying distances and volumes.

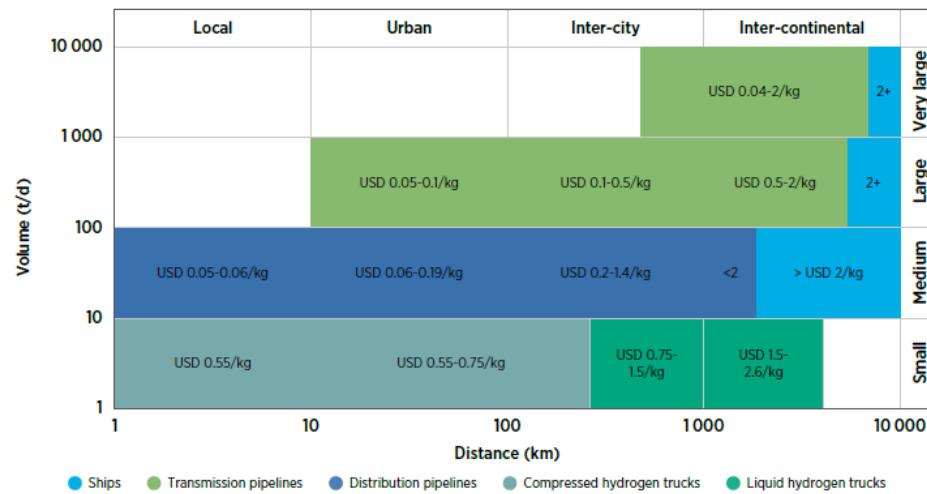


Figure 5: Hydrogen transport cost based on distance and volume⁴

For this work, the main transport solutions have been selected based on their relevance and potential in various hydrogen transportation contexts.

- **Hydrogen pipelines grid:** Hydrogen pipelines provide a cost-effective solution for transporting large volumes over long distances. These can be dedicated to hydrogen pipelines or repurposed natural gas pipelines, making them particularly efficient for connecting hydrogen production facilities to industrial hubs or large-scale users.
- **Compressed Hydrogen Tanks (Types IV) (CH₂):** Commonly used for short- to medium-distance transport, these tanks operate at high pressures (up to 700 bar) to maximize hydrogen storage. Typically transported by trucks, compressed hydrogen tanks offer an effective solution for distributing hydrogen to fuelling stations or industrial sites.
- **Liquid Hydrogen Tanks (LH₂):** This method involves cryogenically cooling hydrogen to -253°C, greatly increasing its volumetric energy density and making it ideal for long-distance transport. Liquid hydrogen tanks are used in specialized trucks, ships, and railcars designed to handle cryogenic temperatures.

3.4.1. Hydrogen Pipelines Grid

Hydrogen can be transported through pipelines similarly to natural gas, providing an efficient and cost-effective method for delivering large quantities over long distances. However, global hydrogen pipeline infrastructure remains limited, spanning only about 4,542 kilometres, primarily in the US and Europe, compared to approximately 1.4 million kilometres of natural gas pipelines⁵. Existing natural gas pipelines could potentially be adapted for hydrogen transport, but several challenges need to be addressed, including hydrogen embrittlement, leakage control, and the lower energy density of hydrogen.

A typical hydrogen or natural gas transmission system generally includes the following components:

- **Gathering Line:** Short pipelines with small diameters that transport hydrogen from production sites to treatment facilities or high-pressure grid injection points, at variable pressure levels.
- **Transmission Line:** A high-pressure line with compressor stations, typically spaced 100 to 200 km apart. Operating pressures range from 25 to 150 bars, and diameters often exceed 1000 mm. This line enables hydrogen blending with natural gas (at concentrations from 5% to 15%) and connects gathering lines to major consumers or final distribution stations. Storage facilities are often included to balance supply and demand.
- **Pressure Reduction and Metering Stations:** These stations reduce the pressure to appropriate levels for distribution, ensuring safe and efficient delivery, and accurately measure gas flow for billing and operational purposes.
- **Distribution Line:** Lines delivering gas to smaller consumers, generally operating at lower pressures (5 to 0.05 bar) and with diameters between 400 and 40 mm.

A possible system for pipeline is presented in Figure 6:

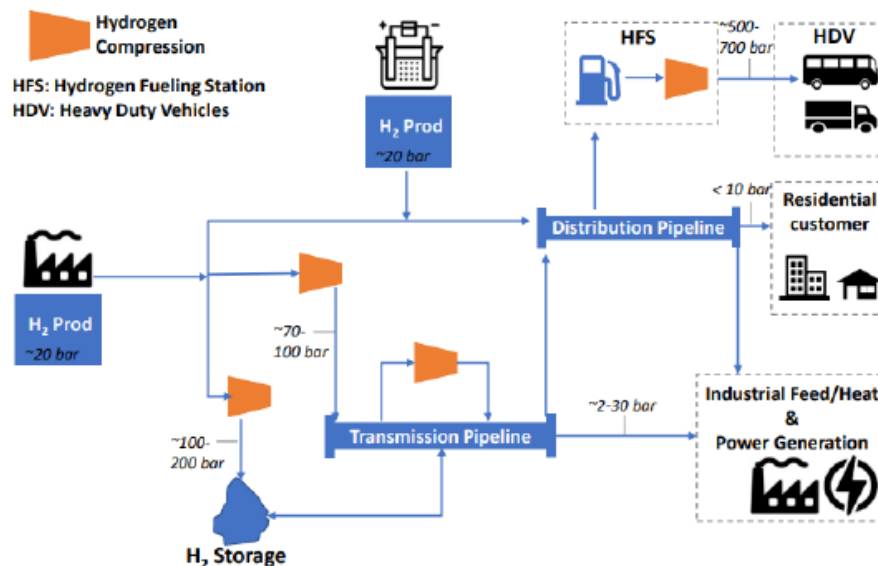


Figure 6: General Transmission and Distribution hydrogen pipeline⁶

Adaptation for a Small-Scale Hydrogen Valley

In this specific analysis for a small hydrogen valley, the infrastructure requirements deviate slightly from traditional hydrogen distribution networks. Given the limited volumes (under 4 tons per day) and the absence of multiple branches for various end users, only the following components are considered:

- **Hydrogen Pipeline:** A simplified pipeline system for transporting hydrogen from production to consumption points within the hydrogen valley.
- **Intermediate Recompression Station:** A station that includes a primary compressor to maintain the necessary pressure over the transport distance.

To define the key operational parameters for these pipelines, this analysis references ASME B31-12.2023 standards to ensure pipeline design compliance. Specifically, operational parameters necessary for preliminary system modelling are outlined in the following section, “4.1 Model description/Parameters definition”.

For pipeline materials, mild low-carbon steels were selected due to their lower susceptibility to hydrogen embrittlement compared to high-alloy steels. Operating pressures for the pipeline are aligned with typical hydrogen distribution pressures, ranging from 10 to 50 bar. To prevent erosion, the distribution velocities are restricted by ASME B31-12 guidelines, which set a maximum allowable hydrogen flow velocity for hydrogen-ready pipelines.

Drawing from multiple studies an initial analysis was conducted on the total investment range required for pipeline installation and operation for end-user distribution. The following parameters summarize the findings⁷⁻⁹:

Table 1: Preliminary Key parameters for Pipeline characterization

Parameter	Value
CAPEX	500-900 k€/km
Nom. pressure	10-50 bar
Maximum erosional velocity	78 m/s (at 30 bar)

For a more detailed assessment of specific investment and operational costs, including main operating parameters, available models have been used⁸. This model, which will be elaborated in the following section “4.1.2 Pipeline transportation”, considers all characteristic cost parameters associated with transmission and distribution lines.

For the intermediate recompression station, given the relatively low flow rates, both reciprocating and centrifugal compressors were considered. Using multiple reciprocating compressors in parallel, along with dampers, allows for nearly constant flow rates comparable to centrifugal compressors. The operational parameters and investment costs for this analysis were determined through a comparison of multiple studies^{1,10,11}.

Table 2: Range of specific compressors investment costs

Parameter	Value
CAPEX	2500-5000 k€/kW

For a more detailed assessment of specific investment and operational costs, including main operating parameters, scaling relationships were applied to account for cost variations and operational requirements, such as required power and specific consumption. These details are further elaborated in the “4.1.2 Pipeline transportation” section.

3.4.2. Compressed gaseous hydrogen tank

Currently, for short to medium distances and lower hydrogen demand (<10 ton/day), compressed gaseous storage transport remains a standard practice. The primary transportation mode is via road, although rail and sea transport can also be utilized if the necessary infrastructure supports hydrogen handling.

There are generally five types of hydrogen tanks, which differ primarily in their technical setup and material selection:

- **Type I:** These are all-metal cylinders, typically made of 4130 steel or 6061 aluminums. They are robust and cost-effective but are relatively heavy and less efficient for high-pressure storage.
- **Type II:** These cylinders have a metal liner (usually 4130 steel or 6061 aluminum) reinforced with a composite wrap, typically made of fiberglass.
- **Type III:** These have a metal liner (usually 6061 aluminum) fully wrapped with a composite material (typically carbon fiber).
- **Type IV:** These are fully composite cylinders with a non-metallic liner (usually plastic) wrapped with carbon fiber. They are extremely lightweight and can store hydrogen at very high pressures, typically up to 700 bar. They are commonly used for onboard vehicle storage and high-pressure dispensing in refuelling stations.
- **Type V:** These are the newest generation of hydrogen storage, made entirely of composite materials without any liner. They offer the highest efficiency in terms of weight and pressure capacity, although they are still under development and less commonly used.

As one moves from Type I to Type V, higher gas pressures are accommodated, resulting in increased gravimetric density of hydrogen and reduced transport weight.

For road-based gaseous hydrogen transport, this study examines Type IV tanks (polymeric-lined tanks fully wrapped with composite materials). The use of composite materials significantly reduces tank weight compared to traditional Type I metal tanks (steel or aluminium), which are limited by their weight to capacities of approximately 300-360 kg of hydrogen per tank.

Market and literature reviews were conducted to establish operational parameters for Tube trailers at 500 and 250 bar. Table 3 lists the key sizes and features of commercially available and prototype options.

Table 3: Main technical parameters for different Type IV tanks

Model	Commercially available					Literature	
	Titan 4	Aether ct	Recoma	Hexagon Purus	Calvera	General	General
H2 stored [kg]	640	822-1005	1000	240-1115	1000-1300	950-1100	580-810
Pressure [bar]	250	400	500	500	517	450-520	250
material	Type IV	Type IV	Type IV	Type IV	Type IV	Type IV	Type IV
Numbers of tubes	4	18-22	\\	22-103	12-16	15-66	9-20
Lengths [m]	12	12	12	3-12	12-14	6-14	6-14

3.4.3. Liquid hydrogen tank

Even if liquified hydrogen has been considered a viable solution for international shipping transportation, there is the possibility of using liquified hydrogen tanks also for road transport since LH₂ is non-corrosive and does not require special anti-corrosion materials.

The main challenge is related to boil off. The boil-off is usually declared as the percentage of LH₂ contained in the vessel that evaporates daily. To mitigate boil-off, storage vessels typically feature double walls with vacuum insulation and additional materials such as alumina-coated polyester sheets. Effective insulation and design can reduce boil-off rates to below 0.1% per day

- **LH₂ tanks** that are generally of three types:
 - Double-jacketed tanks with liquid nitrogen on the outer jacket.
 - Super-insulated tanks with reflective powder or multi-layer insulation, the tanks are realized by two concentric vessels^{12,13}.
 - Vapor-cooled shielded (VCS) tanks employing super-insulation¹⁴.

Table 4: Main technical parameters for liquified tanks

Parameter	Value
Temperature [°C]	-253 ^{15,16}
Density [H ₂ /m ³]	~70 ¹⁵ kg H ₂ /m ³
Maximal filling capacity [%]	90 ¹⁷
Pressure [bar]	<=12
Quantity [kgH ₂]	<= 4'500 (large) <= 2'100 (urban)
Normal evaporation rate (NER) [%]	< 0.5-0.8
Filling time [h]	3-6
Discharging time (depending on size) [h]	0.75-2
Trailer, pressure during transport [bar]	1.4-4.1
Trailer, pressure during filling at Liq. Plant [bar]	0.14 - 0.28
Trailer, pressure during unloading at HRS plant [bar]	Min 2.0

4. METHODOLOGY

In this paragraph will be described the methodology through with the techno economic analysis (TEA) has been conducted, with a brief description of the developed model and the considered inputs with the main assumptions.

Techno economic analysis are techniques to evaluate economical performances of a technology, a process, product or service. These types of analysis are frequently used for evaluating economic feasibility of specific processes/technologies.

For economic feasibility studies as our case, starting from technology-related capital, operating costs and operational parameters of the technologies, the outcomes are mainly levelized cost of the specific technology/product and related economical parameters.

4.1. Model description/Parameters definition

In this chapter the main constituted equations of the model developed in this work are introduced with a description of the operations of the model with the main input and assumptions considered for this specific application.

Key techno-economic parameters considered in the study for each case are reported. Due to the lack of information related to real values for each application, have conducted a literature review analysis for all the evaluated technologies combined with experiences of FBK.

4.1.1. General Parameters definition

This section outlines the general techno-economic parameters and end-user requirements used in the subsequent analyses for various technologies.

To adjust capital expenditures (CAPEX) across different time periods, the Chemical Engineering Plant Cost Index® (CEPCI) was applied as a corrective factor for all technologies considered in this study.

The Chemical Engineering Plant Cost Index® (CEPCI) is a widely used tool for adjusting the construction costs of process plants over time in the chemical process industry. Introduced in 1963, the CEPCI is composed of a composite index with four sub-indexes: equipment, construction labor, buildings, and engineering and supervision. Each sub-index is a weighted sum of several components, most of which are based on Producer Price Indexes (PPIs) published by the U.S. Department of Labor's Bureau of Labor Statistics¹⁸. The CEPCI allows cost adjustments across different periods, making it essential for techno-economic analyses

The yearly CEPCI indexes used in this study are listed below:

Table 5: CEPCI indexes for required years

CEPCI indexes for each year	
Year	Value
2013	567.3
2014	576.1
2017	567.5
2018	603.1
2019	619.2
2020	686.7
2022	816.3
2023	800.6
2024	674.3

The CAPEX values were adjusted to relate to the current year, 2024, using the following equation:

$$\text{CAPEX}_{2024} = \text{CAPEX}_{\text{year } x} * \frac{\text{CEPCI}_{2024}}{\text{CEPCI}_{\text{year } x}}$$

Electricity prices also significantly impact the techno-economic analysis. For this study, average electricity prices within the European market zone for the 2020-2023 period were considered, given that the analysis is conducted within Italy.

The average purchase price for industrial electricity users was derived from ARERA's annual "state of services" reports from 2022 and 2023¹⁹, focusing on gross electricity prices in €/kWh. Due to notable price fluctuations observed between 2020 and 2023, a reference price range for the Euro Area was established between 136 and 249 €/MWh_{el}, with a practical range set between 150 and 250 €/MWh_{el} for scenario calculations. The base case price for this analysis is set at 200 €/MWh_{el}.

4.1.2. Pipeline transportation

The hydrogen distribution through pipelines has been modelled with the following primary components:

- **Pipelines:** This includes both distribution and main service pipelines, constructed from low-strength steel or high-strength polyethylene (PE) materials that are compatible with 100% hydrogen distribution⁸. These pipelines connect hydrogen production centers (e.g., electrolysis plants) with end-users.
- **Compression Station:** Compression stations are required along the pipeline to compensate for pressure losses and to maintain delivery pressure levels consistent with those at the electrolyser outlet.
- **Final Pressure Reduction or Recompression Station:** Upon reaching the destination, hydrogen is adjusted to the specific pressure requirements of the end-user. To account for this, a recompression or pressure reduction station is assumed, depending on the hydrogen's end-use application.

To ensure proper pipeline sizing, certain hydrogen conditions have been defined according to the application's requirements, as outlined in Table 6.

Table 6: Parameters for pressure, temperature, and flow velocity at the hydrogen pipeline

Parameter	Value	Description
P_2	User pressure [bar]	Final pressure required by end-users
T_2	25 °C	Temperature maintained within the pipeline
u_2	35 m/s	Flow velocity

These parameters, particularly the flow velocity, are set to prevent excessive erosion of the pipeline walls. Based on guidelines from ASME, B31.12-2023, a flow speed of 35 m/s was chosen to avoid excessive erosive effects on pipelines of smaller diameters.

Pipeline model

To calculate the mass flow rate of hydrogen and determine the required pipeline diameter, several engineering principles are applied, including the universal gas law for compressible fluids and the Darcy-Weisbach equation for pressure loss. The maximum mass flow rate Q_m of a compressible fluid through a cylindrical pipe with a constant cross-section can be expressed as:

$$Q_m = A u_2 \rho = \left(\pi \frac{d^2}{4} \right) u_2 \rho = \left(\pi \frac{d^2}{4} \right) u_2 \left(\frac{P_2}{Z R T_2} \right)$$

where density ρ is calculated using the universal gas law:

$$Pv = P \frac{1}{\rho} = ZRT$$

Here, Z is the compressibility factor of hydrogen, which depends on pressure and temperature. To determine Z for specific temperature and pressure pairs, has been imported a table of values based on temperature in °C and pressure in MPa, then implemented a bilinear interpolation function. The same approach was used to determine dynamic viscosity as a function of temperature and pressure.

With these parameters defined, we can calculate the minimum diameter d_{min} for each flow rate as follows:

$$d_{min} = \sqrt{\frac{4Q_m}{\pi u_2 \frac{P_2}{ZRT_2}}} = \sqrt{\frac{4Q_m RT_2 Z}{\pi P_2 u_2}}$$

This yields a d_{min} value for each flow rate, independent of transport distance. Using this minimum diameter the Reynolds number has been calculated for each flow rate:

$$Re = \rho \frac{u_2 d_{min}}{\mu} = \left(\frac{P_2}{Z R T_2} \right) \frac{u_2 d_{min}}{\mu}$$

where μ , the dynamic viscosity, is a function of both temperature and pressure. This calculation provides a Reynolds number for each hydrogen demand value.

Next, the required inlet pressure P_1 to ensure the delivery pressure P_2 is calculated as

$$P_1 = P_2 + \Delta P$$

The pressure loss ΔP is determined using the Darcy-Weisbach equation:

$$\Delta P = \frac{fL}{d_{min}} \frac{u_2^2}{2}$$

where f is the friction factor, calculated using an empirical formula²⁰:

$$\frac{1}{\sqrt{f}} = -2 \log \left(\frac{\varepsilon/d_{min}}{3.7065} - \frac{5.0272}{Re} \log \left(\frac{\varepsilon/d_{min}}{3.827} - \frac{4.567}{Re} \log \left(\left(\frac{\varepsilon/d_{min}}{7.7918} \right)^{0.9924} + \left(\frac{5.3326}{208.815 + Re} \right)^{0.9345} \right) \right) \right)$$

It has been adopted this empirical formula over the Colebrook-White equation to avoid iterative calculations, which are less suitable for compressible fluid scenarios. Here, L is the pipeline length, while f and d_{min} are vectors dependent on flow rate.

For the absolute roughness ε , it has been used a value of $50 \times 10^{-3} \text{ mm}$ based on Hydelta data²¹. We confirmed that the values of Re and ε/d_{min} met the ranges specified in the study “An Accurate and Computationally Efficient Explicit Friction Factor Model”²⁰. $33 \times 10^3 \leq Re \leq 1.5 \times 10^8$ and $0 \leq \varepsilon/d_{min} \leq 5 \times 10^{-2}$ for each value of L and Q_m analysed.

The specific per-kilometre costs for the pipeline are calculated by factoring in all characteristic cost parameters associated with a transmission and distribution line, as quantified in the study “The

Techno-Economics of Hydrogen Pipelines”⁸. This approach assumes that the pipeline length matches the transport distance directly, without accounting for any potential urban or natural obstacles that may increase the required length. The contributions to the overall specific pipeline cost are shown in Table 7.

Table 7: Main pipeline CAPEX contributes.

Contribute	Equation
Pipeline material	$1.1 * 63027 * e^{(D_{pipe} * 0.0697)}$
Pipeline labour	$1.1 * (-51.393 * D_{pipe}^2 + 43523 * D_{pipe} + 16171)$
Pipeline miscellaneous	$1.1 * (303.13 * D_{pipe}^2 + 12908 * D_{pipe} + 70000)$
Pipeline right of way	$4417.1 * D_{pipe} + 164241$

The costs in Table 7 are presented in \$₂₀₀₉/miles. To determine the specific transportation cost, these values were converted to €/km using the CEPCI index and appropriate conversion factors.

The specific cost of the pipeline was then compared with per-kilometre costs from an internal database, which correlates pipeline costs with internal diameter, as shown in Figure 7.

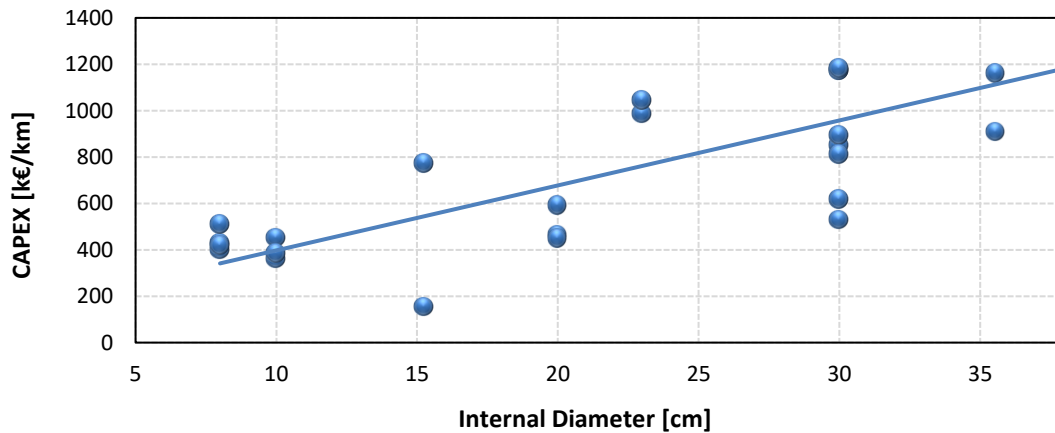


Figure 7: Specific investment costs per unit length as a function of the internal diameter of the pipeline.

Considering a variable CAPEX, derived from the sum of all elements mentioned above, the effective pipeline cost based on the effective transport distance, L , is calculated as follows:

$$Cost_{pipe} = CAPEX_{pipe} * L$$

Pipeline OPEX have been estimated using values in Table 8:

Table 8: Assumed pipeline O&M and WACC values.

Parameter	Value
$O\&M_{pipeline}$	4% CAPEX/year
WACC	8 %

$$OPEX_{pipe\ att} = \sum_{i=1}^{20} \frac{(O\&M_{pipeline} * Cost_{pipe})_i}{(1 + WACC)^i}$$

This results in a cost estimation for each combination of demand and distance, allowing for a precise calculation of pipeline expenses across various scenarios.

Recompression Unit sizing

Defined the initial pressure to ensure the hydrogen specifications on the demand side, sizes and costs of the compression station were defined. The cost of the compressor and compression costs were calculated using an empirical formula that links these to the necessary power for compression²², with an output pressure from the electrolyser of 30 bar and a lifetime of 20 years:

$$\dot{W} = Q_m \frac{R T_2}{M_m} \frac{\gamma}{\gamma - 1} \frac{Z_0 + Z_1}{2} \frac{1}{\eta_s \eta_m} \left[\left(\frac{P_1}{P_0} \right)^{\frac{\gamma}{\gamma - 1}} - 1 \right]$$

With:

Table 9: Main parameters considered for compressor power calculation.

Parameter	Value
Q_m : Hydrogen demand	Case related [kg/s]
M_m : Molar mass of hydrogen	0,002016 kg/mol
R: Universal gas constant	8,314 J/(K * mol)
T_2 : as temperature, assumed constant	293 K
γ : specific heat ratio	1,4
Z_0 e P_0 : Compressibility factor and pressure at electrolyser outlet	$P_0 = 30$ bar
Z_1 e P_1 : Compressibility factor and pressure at the pipeline inlet	Related to losses
η_s : Isentropic efficiency of compression	0,8
η_m : Mechanical efficiency	0,98

For the compressor's investment cost, has been used the Douglas correlation¹⁰, where the compressor power is expressed in kW:

$$CAPEX_{comp} = 5840 * \dot{W}^{0.82} [\text{€}]$$

Operating costs for the compressor were calculated using values in Table 10.

Table 10: Values for calculating variable compression costs.

Parameter	Value
A_0 : Percentage of compressor operating hours	0,85
e: electricity purchase price	0,20 €/kWh
DTE: driver thermal efficiency	0,9
$O\&M_{comp}$: operation and maintenance	8 %CAPEX/year

$$OPEX_{comp} = A_0 H_{year} e \left(\frac{\dot{W}}{DTE} \right) + (O\&M_{comp}) CAPEX_{comp}$$

Final Compression Unit

In cases where final pressures exceed the nominal operating pressure of the pipeline, the final compression station is designed similarly to the recompression station, using the same approach to evaluate the compressor power, the CAPEX and the OPEX.

Final pipeline cost

The initial capital investment is given by the sum of the pipeline cost, installation costs, and the cost of the compressors:

$$Cost_{initial} = Cost_{pipe} + CAPEX_{comp1} + CAPEX_{comp2} + Cost_{install}$$

After discounting the annual hydrogen demand:

$$Q_{m\ att} = \sum_{i=1}^{20} \frac{(Q_m)_i}{(1 + WACC)^i}$$

the levelized cost of transport (*LCOT*) can be calculated as:

$$LCOT = \frac{Cost_{initial} + OPEX_{pipeline\ att} + OPEX_{comp1att} + OPEX_{comp2att}}{Q_{m\ att}}$$

4.1.3. High/medium pressure Tube trailers transport

Hydrogen in gaseous form has a low energy density at atmospheric pressure and ambient temperature compared to traditional fuels, necessitating high-pressure transport in tube trailers to achieve competitive energy delivery. This method offers greater flexibility than pipelines as it does not rely on fixed infrastructure, making it particularly advantageous for delivering hydrogen to locations where pipeline connections are unavailable or for fulfilling temporary hydrogen demands.

Tube trailers

For road-based gaseous hydrogen transport, this study examines Type IV tanks (polymeric-lined tanks fully wrapped with composite materials) as already described in “3.4 Selected transportation technologies” chapter.

The two options considered in this study are:

- 40-feet Type IV tanks at 250 bar
- 40-feet Type IV tanks at 500 bar

To calculate fuel costs for road transport, fuel consumption is based on 0.35 litres/km for an empty truck²³, with a diesel price of 1.7 €/l. Additional fuel consumption, accounting for the weight of the loaded tank, was estimated using a fuel increase of 1.66 litres per 100 km per additional ton of cargo, which corresponds to an additional €0.03/km per ton²⁴. The model assumes that the truck’s outbound trip is fully loaded, while the return trip has reduced fuel costs due to the unloaded hydrogen.

Specific formulas were implemented to determine the annual number of trips per trailer, the number of trailers required to meet demand, and the number of drivers necessary. Table 11 summarizes key data inputs from different studies^{25,26}, and the paragraph “3.4.2 Compressed gaseous hydrogen tank”:

Table 11: Parameters for calculating the number of trips, trailers, and drivers.

Parameter	Value
AOH : Annual trailer usage	2.600 h
v_a : Average speed	50 km/h
F_p : Fuel price	0,63 €/km +0.03 €/km*ton _{H2}
t_l : Loading time	3 h
t_u : Unloading time	1 h
T_c : Driver wage	10 €/h
M_t : Trailer capacity (250 bar)	640 kg
M_t : Trailer capacity (500 bar)	1100 kg
N_w : Daily driver working hours	10 h

From these specifications, the following were calculated:

- Number of Trips: $N_v = \frac{AOH}{\frac{2L}{v_a} + (t_l + t_u)}$
- Numbers of Trailers: $N_c = \left(\frac{Q_m}{M_t * N_w} \right) + 1$
- Number of Drivers: $N_a = \left(\frac{\frac{L}{v_a} + t_l + t_u}{N_w} \right) + 1$

where L is the distance between hydrogen production and delivery points. Results for N_c and N_a were rounded to the nearest whole number.

It has been evaluated annual costs of Fuel (FC) and drivers Wages (LC):

$$\begin{cases} FC = F_p * L * N_v * N_c + (F_p - 0,03 * M_t) * L * N_v * N_c \\ LC = N_v * N_c * N_a * T_c * \left(\frac{2L}{v_a} + t_l + t_u \right) \end{cases}$$

To evaluate the total costs for each trailer, the calculation begins with the capital investment, which is the sum of the costs for each trailer's components (cab and tank) multiplied by the number of trailers needed. Cost references for the cab and tank were drawn from multiple sources, with values provided in Table 12^{23,23,27–29}.

Table 12: Investment and O&M costs for compressed hydrogen transport by truck.

Element	CAPEX	Year
Inv_{truck}	160 k€	2024
$Inv_{trailer}$ 250 bar	650 k€	2018
$Inv_{trailer}$ 500 bar	1100 k€	2017
$O\&M_{truck}$	12 %CAPEX/year	\\
$O\&M_{trailer}$	2 %CAPEX/year	\\

Total investment is given by:

$$Inv_{cap} = N_c (Inv_{truck} + Inv_{trailer})$$

The operating expenses (OPEX) for each trailer are calculated using the O&M values listed in Table 12 for the various truck components, then multiplied by the total number of trailers. These expenses are then discounted over a 20-year operational lifespan to reflect their present value:

$$\begin{cases} OPEX_{CH_2} = (O\&M_{Truck} * Inv_{Truck} + O\&M_{trailer} * Inv_{trailer})N_c \\ OPEX_{CH_2 att} = \sum_{i=1}^{20} \frac{(OPEX_{CH_2})_i}{(1 + WACC)^i} \end{cases}$$

The variable operating expenses are calculated as the sum of driver labour costs (*LC*) and fuel costs (*FC*). These expenses are also discounted to the present value:

$$\begin{cases} varOPEX = LC + FC \\ varOPEX_{att} = \sum_{i=1}^{20} \frac{(varOPEX)_i}{(1 + WACC)^i} \end{cases}$$

Loading Bay

An essential component for a comprehensive techno-economic analysis of hydrogen transport by road is the loading bay, responsible for compressing hydrogen to pressures higher than the operational levels of tube trailers, enabling loading of hydrogen produced or stored onsite. For simplification, the analysis focuses on the key investment and operational cost component of the loading bay: the high-pressure compressor.

Depending on the flow requirements, various compressor types can be utilized. In this analysis, reciprocating compressors are selected due to their suitability for pressures between 350 and 550 bar and flow rates up to 1 000 kgH₂/h. These compressors can also function as low-pressure boosters, operating at inputs below 30 bar.

To calculate the required power for compressing hydrogen from the electrolyser output pressure (assumed to be from a PEM electrolyser) to the trailer's operating pressure, the following formula was adapted from pipeline compression calculations, with adjustments for the specific mass handled by the loading bay:

$$\dot{W} = \dot{m} \frac{R T_2}{M_m} \frac{\gamma}{\gamma - 1} \frac{Z_0 + Z_1}{2} \frac{1}{\eta_s \eta_m} \left[\left(\frac{P_1}{P_0} \right)^{\frac{\gamma}{\gamma - 1}} - 1 \right]$$

Where the mass flow rate $\dot{m}$ in kg/s accounts for a 0.5% hydrogen loss during loading²³ and is calculated as:

$$\dot{m} = \frac{M_t(1 + 0,005)}{3600 t_l}$$

This calculation assumes that the time for gas compression matches the loading time for each trailer. The resulting power requirement is a function of trailer capacity and operating pressure.

Operational costs are proportional to the power (in kW) and the number of annual compressions, reflecting the number of compressors required to meet demand. The annual hydrogen demand, Q_m , is used to determine the number of compressors needed to ensure all trailers are loaded within feasible timeframes. If the total compressor operation exceeds 20 hours per day, additional compressors are introduced to support necessary load operations, calculated as follows:

$$\begin{cases} N_{compr} = \frac{Q_m(1 + 0,005)}{M_t} \\ n_{comp} = int\left(\frac{N_{compr} * t_l}{20} + 1\right) \end{cases}$$

For the compressor's investment cost, has been used the Douglas correlation¹⁰:

$$\begin{cases} CAPEX_{comp} = 5840 * \dot{W}^{0.82} [\text{€}] \\ Inv_{load\ bay} = n_{comp} * CAPEX_{comp} \end{cases}$$

The operational expenses for compression are calculated using the parameters from Table 10:

$$OPEX_{load\ bay} = N_{compr} t_l \left(\frac{\dot{W}}{DTE} \right) e + O\&M_{comp} * Inv_{load\ bay}$$

Unloading Bay

The unloading bay for tube trailers serves to offload hydrogen from the trailers and, if required, to recompress it from the trailer's operating pressure to the final pressure needed by the end-user, such as for a hydrogen refuelling station.

For simplicity, this component is modelled primarily through the high-pressure compressor, as it represents the key element in terms of both initial investment and operating costs. Depending on flow requirements, various types of compressors can be used. This analysis considers reciprocating or diaphragm compressors due to their suitability for low flow rates, with maximum pressures of 1000 bar.

In cases where final pressures exceed the nominal operating pressure of the tube trailers, the unloading and recompression stations are designed similarly to the loading bays, using the same approach to manage high-pressure requirements efficiently.

Final Cost

The total capital investment includes the cost of the required compressors for the loading bay, the optional unloading bay, when is required a higher delivery pressure compared to the one of the tanks, and the trailer components (cab and tank), multiplied by the number of trailers:

$$Inv\ cap = Inv_{load\ bay} + N_c(Inv_{track} + Inv_{trailer}) + Inv_{unload\ bay}$$

After discounting the annual hydrogen demand, the levelized cost of transport can be calculated as:

$$LCOT = \frac{Inv\ cap + OPEX_{load\ bay,att} + OPEX_{unload\ bay,att} + varOPEX_{att} + OPEX_{CH_2,att}}{Q_{m\ att}}$$

4.1.4. Liquefied hydrogen (LH₂) tube trailer transport

To overcome the low energy density of gaseous hydrogen at low pressures, liquid hydrogen transport is a viable solution. Liquid hydrogen allows for significantly higher quantities per trip, approximately three/four times the capacity of 500 bar compressed hydrogen trailers. However, liquefaction is energy-intensive, requiring the hydrogen to be kept at extremely low temperatures (-253°C), and the regasification process incurs additional costs, though these are less substantial.

The main components of the liquid hydrogen transport system considered in this analysis include:

1. Liquefaction
2. Transportation
3. High-Pressure Cryo-Pump
4. Evaporation

Each module's investment costs are based on specific data from multiple studies^{23,29–31}. These costs are proportional to the designed hydrogen capacity of the tanks M_{LH_2} , adjusted for expected losses as boil-off (in percentage) phenomena during transport considered as:

$$M_{LH_2,boil\ off} = M_{LH_2,nom} (1 + \text{Boil off})$$

To accurately size each module in the study, it is essential to account for boil-off losses from the outset. The specific boil-off losses used for each module are shown in Table 13. These values enable a more precise dimensioning of each module by considering the expected hydrogen losses at each stage.

Table 13: Boil off phenomena in each module of the liquefied hydrogen chain²³.

Parameter	Value			
Module	Liquefaction	Transport	HP cryo-pump	Evaporation
Boil off	1,65%	0,1% load x day	0%	0%

Liquefaction

Due to limited data on liquefaction modules for smaller hydrogen volumes, the investment cost for the liquefaction module was estimated by referencing costs from larger-scale liquefaction systems and adjusting them for economies of scale. The values in were used, and the following scaling formula was applied to determine the investment cost based on the processed hydrogen mass. The economic parameters for the evaluation of the liquefaction unit cost are summarised in Table 14.

Table 14: Main techno-economic parameters for the liquefaction unit.

Parameter	Value
Inv_{base}	105M €
$Inv_{compare}$	50 t/day
Inv_{scale}	0,66
$O\&M_{liq}$	8%CAPEX/anno
$el.\ cons_{liq}$	6,78 kWh/kg

$$Inv_{total\ liq} = Inv_{base\ liq} \left(\frac{capacity_{liq}}{Inv_{compare\ liq}} \right)^{Inv_{scale\ liq}}$$

These will be associated with fixed annual costs, which, when discounted over a 20-year plant lifespan with a WACC of 8%, are calculated as follows:

$$fixOPEX_{liq\ att} = \sum_{i=1}^{20} \frac{(O\&M_{liq}(Invest_{total\ liq}))_i}{(1 + WACC)^i}$$

The variable costs for this module are associated with the energy required for hydrogen liquefaction. The annual variable OPEX for liquefaction can be expressed as:

$$varOPEX_{liq} = capacity_{liq} * el.cons_{liq} * e * 1000 * 365$$

where the conversion factor adjusts the "Capacity" from tons per day to kilograms per year. This cost is then discounted over a 20-year period to determine the present value:

$$varOPEX_{liq\ att} = \sum_{i=1}^{20} \frac{(varOPEX_{liq})_i}{(1 + WACC)^i}$$

Liquified hydrogen Trailer

For the transport module, similar formulas used in gaseous hydrogen transport are applied, with parameters shown in Table 15.

Table 15: Main Parameters for characterization of LH₂ trailer.

Parameter	Value
AOH: Annual Operating Hours	2.600 h
v_a : Average Speed	50 km/h
Fp : Fuel Price	0,91 €/km
t_l : Loading Time	3 h
t_u : Unloading time	1 h
Tc : Driver wage	10 €/h
M_t : Trailer capacity	4.300 kg
nw : Daily driver working hours	10 h

- Number of Trips: $N_v = \frac{AOH}{\frac{2L}{v_a} + t_l + t_u}$
- Number of Trailers: $N_c = \left(\frac{Q_m}{M_t * N_v} \right) + 1$
- Number of Drivers: $N_a = \left(\frac{\frac{L}{v_a} + t_l + t_u}{nw} \right) + 1$

In this context, L represents the delivery distance for the hydrogen, and Q_m is the annual hydrogen delivery quantity, which also accounts for boil-off losses during transport. Since transportation losses are reported as a percentage per day, the total loss over the journey is calculated as:

$$Transport\ losses = \left(\frac{0,1}{24} \right) \frac{L}{v_a}$$

Based on these results, fuel (FC) and driver wage (LC) costs can be calculated as follows:

$$\begin{cases} FC = Fp * L * N_v * N_c + (Fp - 0,03 * M_t) * L * N_v * N_c \\ LC = N_v * N_c * N_a * Tc * \left(\frac{2L}{v_a} + t_l + t_u \right) \end{cases}$$

The sum of these costs is actualized as:

$$\begin{cases} varOPEX_{tra} = LC + FC \\ varOPEX_{tra\ att} = \sum_{i=1}^{20} \frac{varOPEX_{tra}}{(1 + WACC)^i} \end{cases}$$

The transport module's investment cost depends on the cost of trailers and their components, as shown in Table 16^{23,29}:

Table 16: investment costs for truck and LH₂ trailer.

Parameter	Value
Inv_{truck}	160.000 €
$Inv_{trailer}$	860.000 €

The total investment for this module can be calculated as:

$$Inv_{tot, LH_2} = N_c(Inv_{truck} + Inv_{trailer})$$

The fixed annual OPEX is then calculated based on the following O&M rates, discounted over the total number of vehicles needed:

Table 17: O&M values for tank and trailer²³.

Parameter	Value
$O\&M_{truck}$	12 %CAPEX/year
$O\&M_{trailer}$	2 %CAPEX/year

The discounted fixed OPEX over a 20-year period with the appropriate WACC is given by:

$$fixOPEX_{tra\ att} = \sum_{i=1}^{20} \frac{(N_c(O\&M_{truck} * Inv_{truck} + O\&M_{trailer} * Inv_{trailer}))_i}{(1 + WACC)^i}$$

This calculation provides the present value of the fixed operational expenses associated with the transport module across its lifetime.

High-Pressure Cryo-Pump and Evaporation Modules

To utilize hydrogen by converting it from liquid to gaseous form at the required usage pressure, additional components like a cryogenic pump and an evaporation module are needed. The evaporation module, an evaporator located at the delivery point, is particularly energy-efficient and free from losses compared to other methods like recompression.

For the cryogenic pump's sizing, it must handle the transported hydrogen volume from the truck within an assumed unloading time of 3 hours. The pump is sized according to hourly demand using the HYDROGEN DELIVERY SCENARIO ANALYSIS MODEL (HDSAM)³², with pump sizing and processing times validated against sector studies³³.

$$W_{cryo\ pump} = \frac{m_{tank}}{t_{comp}} \frac{P_{demand} - P_{tank}}{522 \rho_{LH_2} \eta_p \eta_{el}}$$

where:

- P_{demand} & P_{tank} are in PSI
- $\eta_p = 0.75$ and $\eta_{el} = 0.96$

- ρ_{LH_2} is the average liquid density between inlet and outlet pressures.

The number of cryogenic pumps is determined to ensure all trucks are unloaded within the operational limits with the same methodology used to define the numbers of required compressors for the CH₂ transport case. If daily pump operation exceeds 20 hours, additional pumps are introduced using:

$$n_{cryo\ pump} = int(\frac{n_{unload} * t_u}{20} + 1)$$

Given the limited data, investment and operational costs for cryogenic compression rely on the HDSAM tool, with specific investment costs determined by the final user pressure. Scale economies are not applied due to lack of data.

Table 18: Main Parameters for characterization of cryogenic pumps.

Parameter	Value
$Inv_{700\ bar,spec}$	116 \$/kg _{H₂}
$Inv_{350\ bar,spec}$	71 \$/kg _{H₂}
Inv_{scale}	1
$O\&M_{cryo}$	8 % CAPEX/year
DTE : driver thermal efficiency	0,9

$$Invest_{total\ cp} = n_{cryo\ pump} * W_{cryo\ pump} * Inv_{x\ bar,spec}$$

Annual fixed OPEX and discounted variable OPEX for cryo-pumping are calculated similarly to previous modules.

$$\left\{ \begin{array}{l} fixOPEX_{cp,att} = \sum_{i=1}^{20} \frac{(O\&M_{eva}(Inv_{total\ eva}))_i}{(1 + WACC)^i} \\ varOPEX_{cp} = W_{cryo\ pump} * electricity\ demand_{cp} * e * \left(\frac{1000}{365}\right) \\ varOPEX_{cp,att} = \sum_{i=1}^{20} \frac{(varOPEX_{eva})_i}{(1 + WACC)^i} \end{array} \right.$$

Evaporation Module

The evaporation module is sized based on the hydrogen demand, as it is the final module and is free from losses. Investment and OPEX values are derived from existing studies^{34,35}, as shown in

Table 19:

Table 19: Main Parameters for characterization of evaporation module.

Parameter	Value
Inv_{base}	6000 €
$Inv_{compare}$	1 t/day
Inv_{scale}	1
$O\&M_{eva}$	3 %CAPEX/anno
$el.\ cons_{eva}$	0,075-0,6 kWh/kg

$$Inv_{total\ eva} = Inv_{base\ eva} \left(\frac{capacity_{eva}}{Inv_{compare\ eva}} \right)^{Inv_{scale\ eva}}$$

In this final stage, the term “capacity” corresponds to the total hydrogen demand, as this is the last module and is free from losses.

Like the liquefaction and compression modules, the fixed and variable costs for the evaporation module are calculated and discounted over the total investment duration:

$$\left\{ \begin{array}{l} fixOPEX_{eva\ att} = \sum_{i=1}^{20} \frac{(O\&M_{eva}(Inv_{total\ eva}))_i}{(1 + WACC)^i} \\ varOPEX_{eva} = capacity_{eva} * el.\ cons_{eva} * e * \left(\frac{1000}{365} \right) \\ varOPEX_{eva\ att} = \sum_{i=1}^{20} \frac{(varOPEX_{eva})_i}{(1 + WACC)^i} \end{array} \right.$$

Final Cost

After discounting the annual hydrogen demand, the levelized cost of transport (*LCOT*) can be calculated as:

$$\left\{ \begin{array}{l} Inv_{total} = Inv_{total\ liq} + Inv_{total\ trail} + Inv_{total} + Inv_{total\ eva} \\ varOPEX_{att} = varOPEX_{liq\ att} + varOPEX_{tra\ att} + varOPEX_{eva\ att} \\ fixOPEX_{att} = fixOPEX_{liq\ att} + fixOPEX_{tra\ att} + fixOPEX_{eva\ att} \end{array} \right.$$

$$LCOT = \frac{Inv_{total} + varOPEX_{att} + fixOPEX_{att}}{Q_{m,att}}$$

5. RESULTS

This section presents the results of the sensitivity analysis, starting with a comparison of the transportation technologies studied, followed by an in-depth evaluation of each solution.

Initially, a large-scale analysis will be conducted, examining flow rates and transport distances that extend well beyond those currently characteristic of the Mantova Valley. This preliminary analysis aims to identify performance trends for each transport technology, considering the potential future expansion of the hydrogen valley and larger flow capacities over greater distances.

These analyses will consider the characteristics of different end-users, as previously outlined in Section 3, to determine if specific technologies offer advantages based on varying hydrogen pressure requirements and application fields. This preliminary phase will focus primarily on the total cost of hydrogen transportation.

Following this, a more detailed techno-economic assessment will be conducted, incorporating investment and operational costs, as well as the sizing of the entire transportation chain. This will provide insights not only into the minimum transportation costs but also into the specific plant components that most significantly impact costs for each application.

These analyses will also account for additional components required by the end-user to match the transported hydrogen's characteristics with the specific use case. For example, for hydrogen refuelling stations, a final recompression section will be considered if higher pressures are required to refuel vehicles beyond the operating pressure of compressed hydrogen tube trailers. Similarly, if liquid hydrogen is transported via cryogenic trailers, cryogenic pumps and evaporators will be included in the assessment.

This last point is critical and represents an innovative element in hydrogen transportation TEAs. It allows for quantifying the potential increase in hydrogen sales price associated with high-pressure transport, which could simplify infrastructure requirements and reduce end-user hydrogen costs.

5.1. Low pressure end-users

This section analyses the specific Levelized Cost of Transport associated with delivering hydrogen to thermal users, who require a delivery pressure of 10 bar. The analysis covers hydrogen demands ranging from 1 to 100 tons per day over transport distances between 1 and 100 km.

Figure 8 illustrates the optimal LCOT for the different transportation technologies, based on hydrogen demand (ton_{H_2}/day) and distance (in km), with the required end-user pressure at 10 bar.

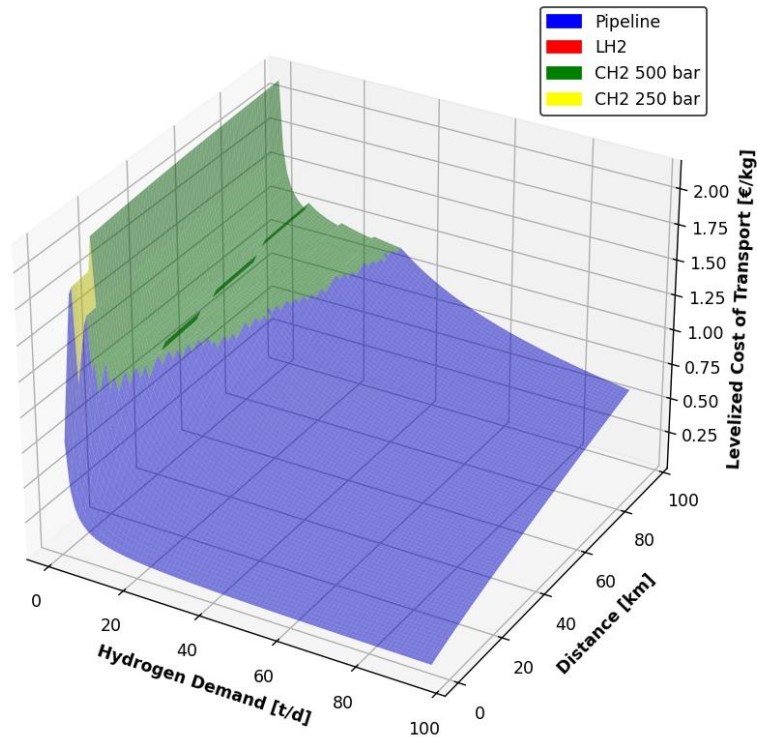


Figure 8: Optimal LCOT for the different transport technologies when the end-user pressure is 10 bar

The chart shows interesting trends related to H₂ quantities and distances thresholds:

1. Over 35 ton_{H_2}/day delivered, pipelines are the most economical transport method. Beyond this threshold, the required number of trucks becomes substantial—over 170 trucks for 100 tons per day over 100 km with 250-bar trailers—making pipeline installation more cost-effective than expanding the truck fleet.
2. For distances under 5 km, pipelines are also preferred, as even at low transport volumes, the cost of trucks and compression systems outweighs the fixed cost of pipeline installation.
3. Under 35 ton_{H_2}/day delivered, pressurized tube trailers at 250 and 500 bars can be more cost-effective than pipelines. The crossover point, where tube trailers (green and yellow areas) become more cost-effective than pipelines (blue area), shifts towards longer distances as the transport volume increases. For example, at demands of 1, 10, and 20 tons per day, tube trailers are more economical for minimum distances of 6 km, 31 km, and 56 km, respectively. This is due to the disproportionate increase in truck-related costs as hydrogen volumes rise compared to pipeline costs. In fact, as the hydrogen volume increases, so do the costs associated with the trucks and the refuelling of the trailers at higher pressures. For this reason, truck transport is only more cost-effective if justified by a longer transport distance, which significantly raises the cost of installing a pipeline for low volumes of hydrogen treated.

The choice between 250 bar and 500 bar tube trailers is the result of a trade-off between the costs of the trucks and the costs associated with the compression and refuelling systems. While 500 bar transport reduces the number of required trucks, it demands a larger compression system. In contrast, 250 bar transport involves more trucks, but the individual truck cost is lower, and the compression system is smaller, but as the daily demand increases, the number of compressors required is greater compared to high-pressure transport.

For low hydrogen volumes, the 250 bar option is generally more economical. For medium to high volumes, as fleet and compressor requirements grow, the 500 bar option becomes preferable due to its higher capacity, avoiding the need for additional trucks at certain thresholds.

Figure 9a depicts the levelized cost of transport trend respect to the hydrogen demand at various distances when hydrogen is transported by pipeline. For medium and long distances, transporting small quantities of hydrogen is relatively expensive. Specifically, transporting 1 ton of H₂ per day over distances of 20, 40, and 60 km results in costs of 5.1, 9.4, and 13.7 €/kg_{H₂}, respectively. The curves show a steep decline as demand increases, with the cost for 10 tons per day over 60 km dropping to 2 €/kg_{H₂}. The slope of the curves then decreases, and the threshold of 1 €/kg_{H₂} is reached for transported quantities between 7 and 24 tons of hydrogen per day, in the 20-60 km range. By increasing the transported quantity to 100 tons per day, the specific cost decreases further, reaching minimum values in the 0.16-0.4 €/kg_{H₂} for distances of 20-60 km. Short-distance transport shows reduced costs across the entire range of transported quantities, going from 0.79 €/kg_{H₂} for 1 ton per day to as low as 0.03 €/kg_{H₂} for 100 tons per day.

Figure 9b shows the LCOT trend respect to the transport distance for different hydrogen demand. As the transported quantities increases, the transport specific cost becomes progressively less sensitive to distance, with the curves flattening out horizontally. Conversely, at lower flow rate, the curves become steeper, indicating that distance has a greater impact on cost per kilogram of hydrogen. In fact, for low flows, investment depreciation costs are not adequately compensated, and increasing the length of the pipeline leads to progressively higher specific costs. For instance, at a daily demand of 1 ton, pipeline transport costs range from 0.79 €/kg_{H₂} at 1 km to 22 €/kg_{H₂} at 100 km. Conversely, for a demand of 60 tons per day, LCOT varies between 0.04 and 0.84 €/kg_{H₂} for distances of 1 km to 100 km.

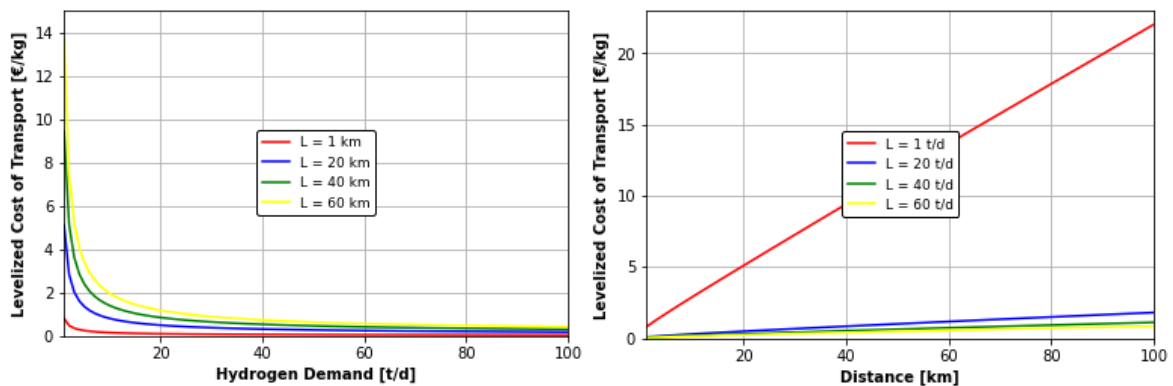


Figure 9: Pipeline LCOT trend with hydrogen demand (a) and transport distance (b) variations.

Figure 10 a,b provides a comparison of LCOT for different truck-based transport technologies (low pressure compressed, high pressure compressed and liquified hydrogen) across the shortest and the longest transport distances, as transported quantity varies. For all technologies and distances, the LCOT trend mirrors that of pipeline transport:

- A significant reduction when moving from low to medium quantities, and as the transport quantity increases, the rate of cost reduction diminishes.
- The percentage reduction with the volume of hydrogen is greater for liquefied hydrogen technology compared to compressed hydrogen. This is because the larger portion of the transportation cost with liquid hydrogen is attributed to the liquefaction and gasification processes, which benefit from greater economies of scale compared to purchasing multiple carriers and compressors.
- Liquefied hydrogen transport remains the least economical in all scenarios, with specific costs always exceeding 2 €/kg_{H₂} for both short and long distances and any demand levels, exceeding 5 €/kg_{H₂} for low demand at any distance.
- The LCOT for compressed hydrogen ranges from 1 to 3 €/kg_{H₂} for low hydrogen volumes, and from 1 to 2 €/kg_{H₂} for medium and high hydrogen demands: With the 500 bars tanks also reaching values below 1 €/kg_{H₂} for short distances and medium to high hydrogen delivered.

Figure 10 c,d, depicts the LCOT trend with transport distance across the different technologies, for both the lowest and the highest hydrogen demands. Transportation distance has a smaller impact on the specific cost of compressed and liquefied hydrogen technologies compared to pipeline transportation, where costs increase due to both the pipeline infrastructure and additional compression to compensate for pressure losses over longer distances. For compressed hydrogen, increasing distance leads to higher operational costs associated with trucks and trailers, which may require additional vehicles if the existing fleet cannot cover the entire route. A similar effect occurs with liquefied hydrogen, where increasing distance also raises costs due to higher liquefaction and gasification requirements, as well as losses from boil-off.

Pressurized transport at 500 bars is less cost-effective than at 250 bars in the case of a daily demand of one ton across the entire range of distances analysed, as the amortization of more expensive transport systems becomes inefficient at very low transport volumes. This effect is even more pronounced with liquefied hydrogen technology, where the high investment cost of the liquefaction system dominates. The jumps in LCOT in Figure 10c is due to the increase in the number of trucks and trailers as transport distance increases. Specifically, for 500 bars transport, one truck is sufficient up to 80 km, while two are needed for 100 km. In contrast, for transport at 250 bars, one truck suffices for 1 km, but two trucks are required for longer transport distances. For liquefied hydrogen, one truck can handle the entire 1-100 km range.

For long distances or high hydrogen demand, compressed hydrogen at 500 bars proves to be the most cost-effective among road transport technologies. For instance, transporting 100 tons per day results in specific costs ranging from 0.84 €/kg_{H₂} at 1 km to 1.14 €/kg_{H₂} at 100 km. Conversely, for transporting 1 ton per day over 1 km, low-pressure compressed hydrogen is the most economical option, costing around 1.79 €/kg_{H₂} compared to 2.01 €/kg_{H₂} for high-pressure and 5.27 €/kg_{H₂} for liquefied hydrogen

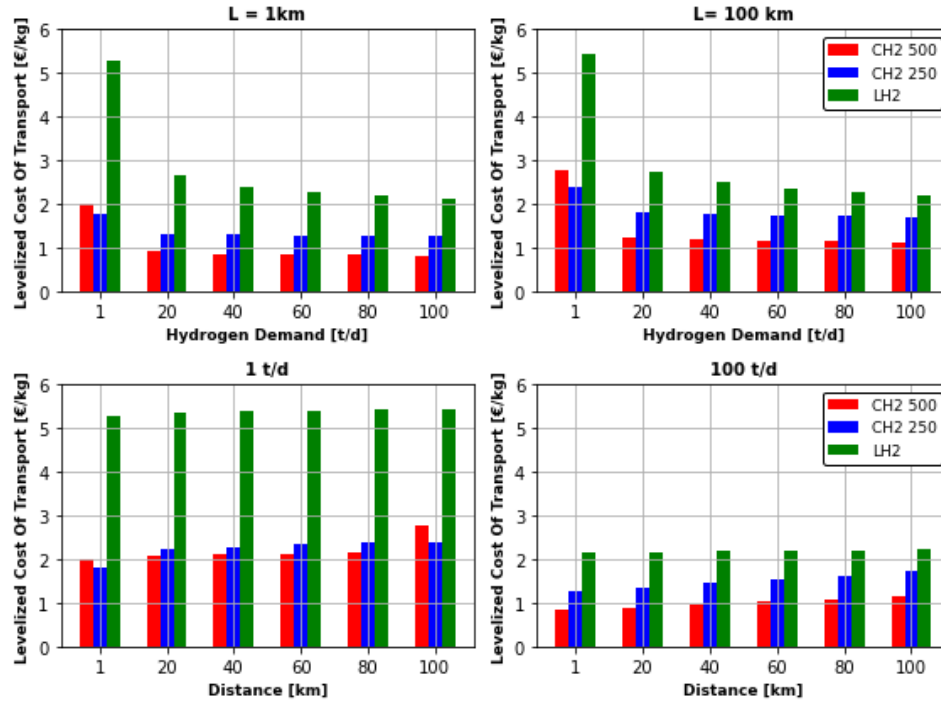


Figure 10: Truck-based transport LCOT trend with H₂ demand (a,b) and transport distance (c,d) variation

Table 20 summarizes the LCOT for the different transportation methods, based on some characteristic hydrogen demand and distance values.

Table 20: LCOT for the different transportation methods for the low-pressure end user case

H ₂ Demand	Technology	LCOT [€/kg]			
		1 [km]	25 [km]	50 [km]	100 [km]
1 [t/d]	Pipeline	0.79	6.19	11.55	22.03
	CH ₂ 250 bar	1.79	2.23	2.3	2.40
	CH ₂ 500 bar	2.01	2.07	2.11	2.77
	LH ₂	5.27	5.34	5.39	5.44
25 [t/d]	Pipeline	0.07	0.49	0.85	1.53
	CH ₂ 250 bar	1.32	1.43	1.54	1.78
	CH ₂ 500 bar	0.88	0.96	1.06	1.21
	LH ₂	2.57	2.60	2.62	2.66
50 [t/d]	Pipeline	0.04	0.31	0.53	0.95
	CH ₂ 250 bar	1.29	1.40	1.52	1.75
	CH ₂ 500 bar	0.86	0.93	1.02	1.18
	LH ₂	2.32	2.35	2.37	2.41
100 [t/d]	Pipeline	0.03	0.19	0.34	0.61
	CH ₂ 250 bar	1.27	1.38	1.49	1.72
	CH ₂ 500 bar	0.83	0.91	0.99	1.14
	LH ₂	2.13	2.16	2.18	2.21

5.2. Medium and High-pressure end-users

Figure 11 illustrates the optimal LCOT for various transportation technologies, based on hydrogen demand and distance, with the user pressure requirement set at 350 (left) and 700 bar (right).

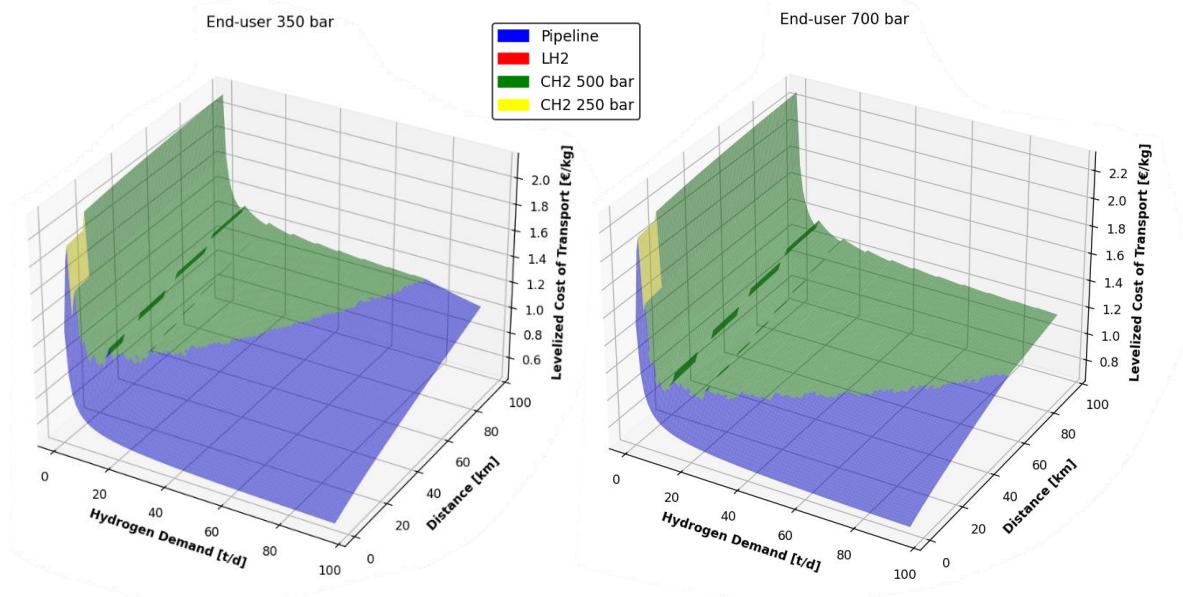


Figure 11: Optimal LCOT for the transport methods with 350 (left) and 700 bar (right) end user pressure

As the pressure required by the end user increases, transporting hydrogen via tube trailers broadens the range of applications where this method is more cost-effective than using pipelines. This is primarily due to the significant impact of hydrogen flow rate on the pipeline compressor system costs, as it necessitates a compressor to raise the line pressure to the required level for the user. High-pressure disadvantages pipeline transport, as the costs associated with the recompression station increase and are added to the installation costs of the pipeline itself.

- For the 350 bar case, pipelines are always more economical for volumes greater than 78, beyond which the costs of trucks and compression systems for refuelling become significantly impactful. Below this volume threshold, there are conditions under which pressurized technology can be more advantageous than pipeline transport.
- For the 700 bar case study, there is no longer a hydrogen demand limit above which it is always advantageous to use the pipeline. Instead, the use of tube trailers may be preferable to the pipeline at any flow rate, depending on the distance travelled. In addition, for distances greater than 70 km, pipeline transport is consistently less economical compared to compressed hydrogen transport.

For short distances and low flow rates, transport using low-pressure tube trailers can be the most economical. However, since for 250 bar gas cylinder trucks, the pressure required by the end user is (for these case study) greater than the transport pressure, the costs related to the recompression station have to be added to the overall cost. This suggests that transportation via high-pressure trailers becomes more economical when hydrogen needs to be transported in larger volumes and over greater distance, as shown in Figure 11.

Table 21 and Table 22 summarize the LCOT for the different transportation methods for medium and high-pressure end user respectively, based on some hydrogen demand and distance values. The

Tables also indicate the percentual increase of the specific cost with respect to the case of low-pressure end user.

Table 21: LCOT for the different transportation methods for the medium-pressure (350 bar) end user case

H ₂ Demand	Technology	LCOT [€/kg]							
		1 [km]		25 [km]		50 [km]		100 [km]	
		350 [bar]	↑%	350 [bar]	↑%	350 [bar]	↑%	350 [bar]	↑%
1 [t/d]	Pipeline	1.29	63	6.69	8	12.06	4	22.53	2
	CH ₂ 250 bar	1.89	6	2.34	5	2.41	5	2.50	4
	CH ₂ 500 bar	2.01	0	2.07	0	2.11	0	2.77	0
	LH ₂	5.52	5	5.59	5	5.64	5	5.69	5
25 [t/d]	Pipeline	0.52	643	0.94	92	1.3	53	1.98	29
	CH ₂ 250 bar	1.38	5	1.49	4	1.61	5	1.83	3
	CH ₂ 500 bar	0.88	0	0.96	0	1.06	0	1.21	0
	LH ₂	2.62	2	2.65	2	2.67	2	2.71	2
50 [t/d]	Pipeline	0.48	1100	0.75	142	0.98	85	1.39	46
	CH ₂ 250 bar	1.34	4	1.45	4	1.57	3	1.79	2
	CH ₂ 500 bar	0.86	0	0.93	0	1.02	0	1.18	0
	LH ₂	2.37	2	2.40	2	2.42	2	2.46	2
100 [t/d]	Pipeline	0.46	1433	0.63	232	0.79	132	1.05	72
	CH ₂ 250 bar	1.32	4	1.43	4	1.54	3	1.76	2
	CH ₂ 500 bar	0.83	0	0.91	0	0.99	0	1.14	0
	LH ₂	2.18	2	2.20	2	2.22	2	2.26	2

Table 22: LCOT for the different transportation methods for the high-pressure (700 bar) end user case

H ₂ Demand	Technology	LCOT [€/kg]							
		1 [km]		25 [km]		50 [km]		100 [km]	
		700 [bar]	↑%	700 [bar]	↑%	700 [bar]	↑%	700 [bar]	↑%
1 [t/d]	Pipeline	1.53	94	7.14	15	12.51	8	22.77	3
	CH ₂ 250 bar	2.11	18	2.55	14	2.62	14	2.71	13
	CH ₂ 500 bar	2.16	7	2.22	7	2.26	7	2.92	5
	LH ₂	5.70	8	5.78	8	5.82	8	5.87	8
25 [t/d]	Pipeline	0.73	943	1.16	137	1.51	78	2.15	41
	CH ₂ 250 bar	1.49	13	1.60	12	1.71	11	1.95	10
	CH ₂ 500 bar	0.94	7	1.02	6	1.09	3	1.26	4
	LH ₂	2.67	4	2.70	4	2.72	4	2.76	4
50 [t/d]	Pipeline	0.70	1650	0.97	213	1.19	125	1.59	67
	CH ₂ 250 bar	1.46	13	1.57	12	1.68	11	1.91	9
	CH ₂ 500 bar	0.91	6	0.99	6	1.07	5	1.23	4
	LH ₂	2.42	4	2.44	4	2.47	4	2.51	4
100 [t/d]	Pipeline	0.67	2133	0.86	353	1.01	197	1.28	110
	CH ₂ 250 bar	1.43	13	1.54	12	1.66	11	1.88	9
	CH ₂ 500 bar	0.89	7	0.96	5	1.04	5	1.19	4
	LH ₂	2.23	5	2.25	4	2.27	4	2.31	5

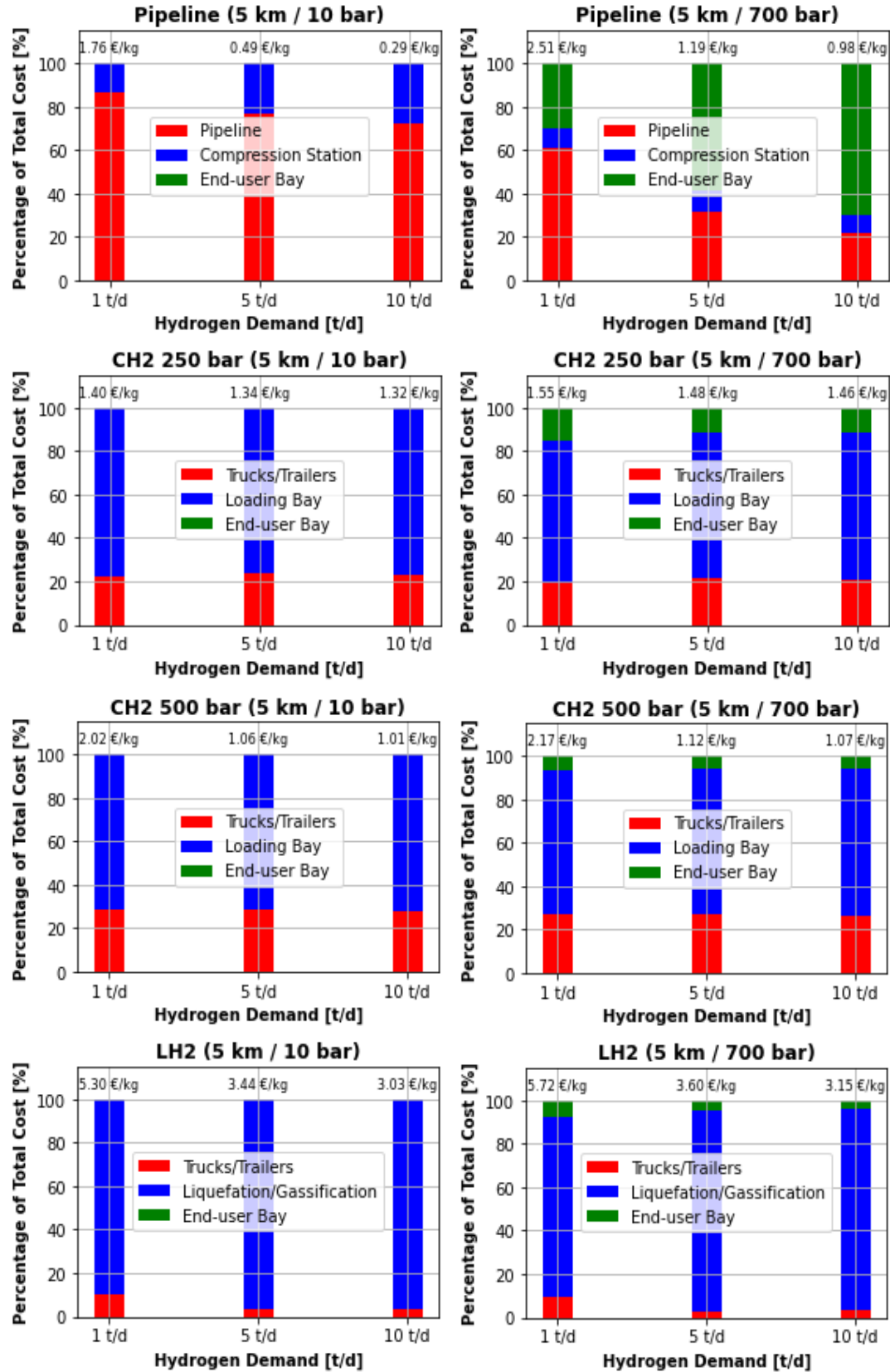
The percentage increase in LCOT shown in the red column represents the additional cost incurred from the increased pressure required by the end-user. In this analysis, this cost is considered part of the transportation expenses, meaning that LCOT includes all infrastructure and processes necessary to deliver ready-to-use hydrogen from the producer to the end user. Alternatively, this cost can be excluded from the LCOT and instead attributed to the overall costs borne by the end user.

5.3. Costs Breakdown

In this section a breakdown of the LCOT is carried out, focusing on the case study of HYMANTOVALLEY project. For this purpose, the hydrogen demand and the distance upper bound has been limited to 10 tons per day and 10 kilometres, respectively. In the first analysis, the cost breakdown was carried out by summing up the CAPEX and OPEX of each section for each transport methodology. Specifically, for the transport via pipeline, the breakdown is based on the investment and operational costs of the pipeline, those related to the recompression station, and those for the compression before the refuelling bay for the end user. Similarly, for compressed hydrogen technologies, the three cost items include the investment and operational costs for trucks and trailers, those related to the loading compression station, and those for refuelling the end user. Finally, for liquid hydrogen transport, in addition to the investment and operational costs for trucks and trailers and compression for the end user, the costs related to the liquefaction and gasification section are also included.

The results of the analysis related to low pressure (10 bar) and high-pressure end-users (700 bar) are first presented where all contributions are included. The results for the 350-bar case show intermediate values between the two cases presented, and therefore the representation is omitted. Figure 12 shows the cost breakdown for all technologies, when the transport distance is 5 km for three different values of hydrogen demand. Bar charts depict values for the 10-bar end-user scenario on the left, and 700-bar scenario on the right, respectively. The graph also indicates the LCOT values to which the cost allocation refers.

- In pipeline transport for low-pressure end users, the investment and operational costs of the pipelines represent the predominant share of expenses over the operating years, with a contribution consistently exceeding 70%. As the transported hydrogen flow rate increases, compression costs also become a significant portion, rising from 13.7% to 27.8%. When the end user requires hydrogen at high pressure, the largest share of the total cost increasingly shifts towards the expense for investment and operating for the final compression, as the amount of hydrogen increases. Specifically, for the transport of 10 tons per day of hydrogen over 5 km for use at 700 bars, the weight of the pipeline cost drops to 21.6%, while costs related to the final compression account for approximately 70%.
- For the transport technology using tube trailers, the cost of the trailers and trucks ranges between 22% and 24% of the total cost for a transport pressure of 250 bar, and between 27% and 29% for a transport pressure of 500 bar. In this case, the increase in pressure required by the end user has less impact on the cost allocation since most of the compression work is done at the loading bay, which indeed represents the dominant cost share in all scenarios. Furthermore, unlike what happens with pipelines, the share of the cost for final re-compression at the end-user decreases as the requested quantity increases, dropping from 15% to 11%, and from 7% to 5%, respectively in the case of tube trailers at 250 bars and 500 bars.
- In the case of transportation via liquefied hydrogen, the largest contribution to total expenses comes from the investment and operation and maintenance costs of the liquefaction and gasification section, which accounts for at least 85% in every scenario analysed. The expenses related to final compression do not represent a significant relative cost, amounting to 5% for hydrogen production of 1 ton per day, and decreasing to around 4% for larger production volumes.

Figure 12: Cost breakdown, when the transport distance is 5 km for three different values of H₂ demand

In the second part of the analysis, CAPEX and OPEX are considered separately for each technology of transport. While the previous goal was to visualize the contribution of the various sections of the transportation infrastructure to the total expenses, the focus then shifts to comparing the weight of investment costs and operational costs in relation to the total costs.

Table 23 reports the LCOT values for the case study under examination, along with the respective percentages of CAPEX and OPEX in the low and high-pressure end-user scenarios.

Table 23: LCOT values with respective weight of CAPEX and OPEX for low- and high-pressure end user cases

H2 Demand	Technology	10 [bar]			700 [bar]		
		LCOT [€/kg]	CAPEX [%]	OPEX [%]	LCOT [€/kg]	CAPEX [%]	OPEX [%]
1 [t/d]	Pipeline	1.76	43.5	56.5	2.51	34.3	65.7
	CH ₂ 250 bar	1.40	25.1	74.9	1.55	25.9	74.1
	CH ₂ 500 bar	2.02	42.5	57.5	2.17	42.3	57.7
	LH ₂	5.30	41.9	58.1	5.72	42.2	57.8
5 [t/d]	Pipeline	0.49	36.0	64.0	1.19	20.1	79.9
	CH ₂ 250 bar	1.34	14.9	85.1	1.48	14.4	85.6
	CH ₂ 500 bar	1.06	26.4	73.6	1.12	25.9	74.1
	LH ₂	3.44	33.6	66.4	3.60	33.2	66.8
10 [t/d]	Pipeline	0.29	33.2	66.8	0.98	16.2	83.8
	CH ₂ 250 bar	1.32	13.3	86.7	1.46	12.9	87.1
	CH ₂ 500 bar	1.01	23.0	76.0	1.07	23.5	76.5
	LH ₂	3.03	30.4	69.6	3.15	29.8	70.2

In the case of transporting one ton per day via pipeline, CAPEX accounts for approximately 43% of the total costs. When the transported flow increases, both the cost of the pipeline (due to the larger diameter) and the cost of the compressor (due to increased capacity) rise. However, operational costs increase more than the investment costs, and the share of CAPEX decreases to around 36% and 33% for hydrogen demand of 5 and 10 tons per day, respectively. This is because, while CAPEX generally follows an economy of scale (for example, for the compressor according to equation X), OPEX is composed of two contributions: fixed costs, which are a percentage of the investment costs and therefore also scale non-linearly, and variable costs, which instead depend on the volumes and energy involved and do not follow an economy of scale. Figure 13 shows the trend of pipeline and compression station investment and operating costs with the hydrogen demand. As the demand rises from 1 ton per day to 10 tons per day, the cost of the pipeline experiences an increase of approximately 19%, rising from around €2.6 million to approximately €3.1 million, while the costs for the recompression station increase by approximately 2.8 times, amounting to about €360,000 for the maximum daily hydrogen demand. OPEX increases with the required flow rate at a steeper rate than CAPEX. Specifically, pipeline operating costs increase by around 57%, ranging from around 2.8 million to approximately 4.5 million, while compression station operating costs increase by approximately 2.5 times, accounting for about €2.5 million for 10 tons per day of hydrogen delivered.

When the pressure required by the end-user is 700 bar, the predominant cost becomes that of the final compression, as shown in Figure 13 OPEX experiences a significant increase, rising from 65.7% for a hydrogen demand of 1 ton per day to 79.9% and 83.8% for flow rates of 5 and 10 tons per day, respectively.

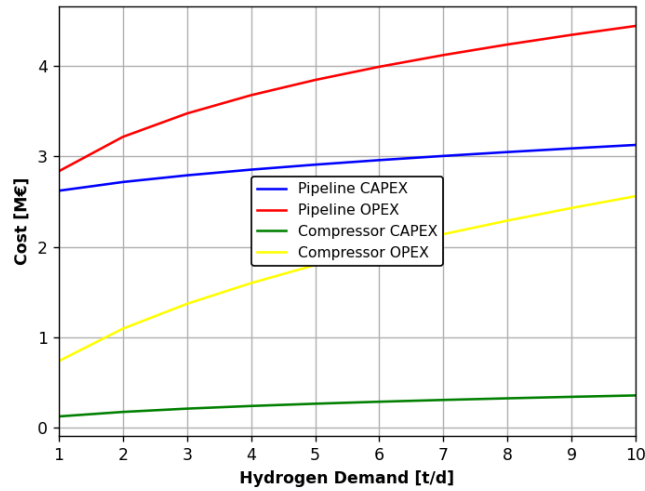


Figure 13: Pipeline and compression station CAPEX and OPEX for low pressure end user

The investment and operating costs trend with the daily demand of the other technologies follows the same logic that was explained for the pipeline transportation scenario. Specific values are reported in Table 21. The 250-bars compressed hydrogen transport is the technology that required the lowest capital investment in percentual. Specifically, the weight of the CAPEX on the total cost ranges from 25.1% to 13.3%. In absolute terms, low pressure compressed hydrogen transport exhibits the lowest capital expenditure for hydrogen demand less than 4 tons per day. For higher hydrogen volumes, pipeline investment costs result to be the lowest, due to the increase in the trucks, trailers and compressors costs for by road transport, with hydrogen demand. Liquefied technology presents the highest CAPEX, mainly due to the costs of liquefaction and gasification plants. Figure 14 shows the trend of the capital cost with the quantity of daily hydrogen produced, for the transport method analysed in this work.

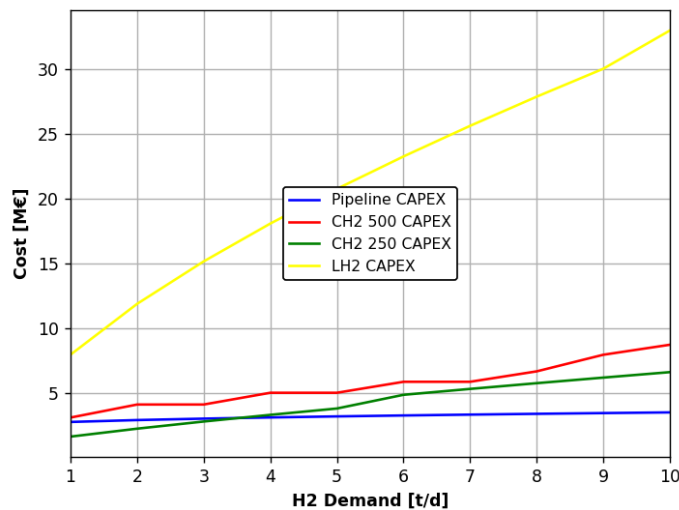


Figure 14: CAPEX of transport methods for low pressure end user case

5.4. Conclusions

- At low pressures and for certain user requirements, pipeline transport proves to be the most cost-effective method across a wide range of distance and hydrogen demand combinations, with costs reaching as low as 0.03 € per kilogram for delivering 100 tons per day over a 1 km distance.
- Compressed tube trailer transport becomes competitive for distances over 5 km and hydrogen demand below 35 tons per day. Specifically, transporting hydrogen compressed to 250 bars is the most economical option for delivering 1 ton per day over distances between 6 and 11 km. Transporting liquefied hydrogen is consistently the most expensive option, with costs always exceeding 2 € per kilogram.
- As the pressure required by the end user increase, hydrogen transport via tube trailers becomes cost-effective across a broader range of applications compared to pipeline transport. In the 700-bar case study, for distances exceeding 70 km, pipeline transport is consistently less economical than compressed hydrogen transport, which reaches a minimum cost of 1.19 €/kg for transporting 100 tons per day over a 100 km distance.
- The cost breakdown shows that pipeline costs account for more than 70% for low-pressure end user, and approximately 20% for high-pressure end user. When the end user requires hydrogen at high pressure, the largest portion of the total cost progressively shifts toward the investment and operating expenses associated with final compression.
- For the transport technology using tube trailers the increase in pressure required by the end user has less impact on the cost allocation since most of the compression work is done at the loading bay, which indeed represents the dominant cost share in all scenarios. In the case of transportation via liquefied hydrogen, the largest contribution to total expenses comes from the investment and operation and maintenance costs of the liquefaction and gasification section, which accounts for at least 85% in every scenario analysed.
- In absolute terms, low-pressure compressed hydrogen transport has the lowest capital expenditure for hydrogen demands under 4 tons per day. For higher hydrogen volumes, pipeline investment costs are the lowest, due to the rising costs of trucks, trailers, and compressors for road transport as hydrogen demand increases. Liquefied hydrogen transport, on the other hand, incurs the highest CAPEX, primarily due to the costs of liquefaction and gasification plants

6. CASE STUDY CONTEXT WITHIN THE VALLEY

The final section identifies the most probable end-users within the valley and evaluates hydrogen transportation costs for the different solutions previously analysed, based on actual flow rates and distances relevant to these users. By aligning projected transport costs with real-world demand and constraints, the analysis offers a clear picture of how hydrogen can be efficiently delivered to key local stakeholders within the valley framework.

6.1. Veneziana di Navigazione e Rimorchio SRL

Ve.Na (Veneziana di Navigazione e Rimorchio SRL) operates as a heavy-duty tugboat transport company, active along the Po River and the Adriatic Sea. In collaboration with Future Proof Shipping, VeNa is developing a hybrid tugboat powered by a diesel-electric drivetrain integrated with a fuel cell system and compressed hydrogen storage.

- Expected hydrogen demand: 50 tons/year
- Refuelling location: Valdaro Port
- Distance from H₂ production plant (SAPIO, Mantova): 1.7 km

6.2. APAM Esercizio S.p.A

APAM, the public transport operator of Mantova, is planning to introduce six hydrogen buses into its fleet. These vehicles will contribute to the city's efforts toward sustainable and zero-emission public mobility.

- Expected hydrogen demand: 15 tons/year
- Refuelling location: APAM depot
- Distance from SAPIO plant: 8.1 km

6.3. TEA S.p.A

A TEA is a multi-utility company managing public services in the sectors of water, waste, and energy. Within the hydrogen valley context, TEA is expected to use hydrogen to support district heating operations.

- Expected hydrogen demand: 300 tons/year
- Application: Energy for heating
- Distance from SAPIO plant: 1.6 km

In this specific case, a dedicated hydrogen pipeline is available, although it does not fully cover the path to the production site. For this reason, and in general for the sake of a comprehensive analysis, the installation of a new pipeline was still considered, ensuring compliance with distance, flow rate, and operating pressure requirements.

6.4. Potential Users Cost of Delivery of Hydrogen

Have been identified other potential users but due to uncertainties of participation and request of hydrogen demand haven't been taken into account. As a precautionary measure, the intermediate case with a pressure level of 350 bar, as identified in the Chapter " 4.1.3 High/medium pressure Tube trailers transport ", has been selected as the reference end-user scenario. This pressure is well-suited for use in both buses and ships and is a typical on-site storage pressure to ensure a continuous supply for use in boilers, CHP, or other energy applications.

Summing up the potential users of the valley described before:

User	Distance from Sapio [km]	Daily flow rate [tons/day]	Annual flow rate [tons/year]
Ve.Na	1.7	0.14	50
APAM S.p.A	8.1	0.04	15
TEA S.p.A	1.6	0.82	300
Total	11,4	1	365

A total daily hydrogen demand of one tonne was considered, which the different transport technologies must satisfy within a standard working day.

The distances between the SAPIO production site and the end-user previously indicated refer to straight-line distances; the actual total transport distance has been estimated at approximately 25 km, for each delivery cycle.

The total daily transportation costs for each solution are illustrated in the following figure:

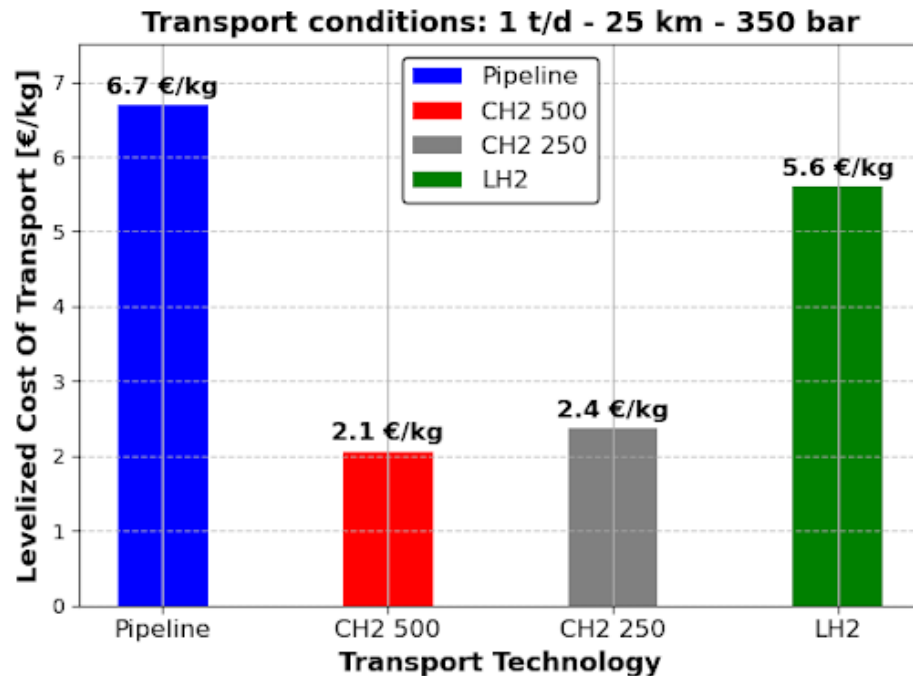


Figure 15: LCOT of hydrogen for specific end-users within the valley boundaries.

As shown, hydrogen distribution via Type IV high-pressure trailers (500-bar) emerges as the most cost-effective solution, with a Levelized Cost of Transport (LCOT) of approximately 2.1 €/kg_{H2}. This advantage is mainly attributable to the short delivery distances, the centralized location of the hydrogen production plant, and the ability to meet the daily demand using a single trailer (unlike

the 250-bar trailer option) which altogether make this solution well-suited for continuous daily operations.

In contrast, pipeline distribution proves to be the least favourable option, with a Levelized Cost of Transport (LCOT) of approximately 6.7 €/kg_{H2}. This is primarily due to the high installation costs, which are not offset by the short distances and relatively low flow rates considered in this case. The detailed evaluation of these cases is aligned with the one conducted and detailed in the previous chapter “5.3 Costs Breakdown”.

Additional potential users identified include IPE Locomotori s.r.l. and Versalis S.p.A. The former involves the use of locomotives in the Valdaro port area, while the latter envisions the use of a hydrogen boiler in the existing plant. Although the required transport distances are known, the exact hydrogen demand has not yet been clearly defined. For this reason, these users were not considered in the previous analysis.

Once the demand profiles of the users, as well as other potential ones, have been defined in a detailed and accurate manner, it will be possible to develop a business model for the Valley in the following work package “WP4 – Business Models and Commercialisation”. This will allow for the evaluation of the most efficient hydrogen transport systems for the specific case under analysis.

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