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ANALYSIS OF THE CURRENT HYDROGEN COST STRUCTURE

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The European Commission is supporting the Coordination Action "HyLights" and the Integrated Project "Roads2HyCom" in the field of Hydrogen and Fuel Cells. The two projects support the Commission in the monitoring and coordination of ongoing activities of the HFP, and provide input to the HFP for the planning and preparation of future research and demonstration activities within an integrated EU strategy.

The two projects are complementary and are working in close coordination. HyLights focuses on the preparation of the large scale demonstration for transport applications, while Roads2HyCom focuses on identifying opportunities for research activities relative to the needs of industrial stakeholders and Hydrogen Communities that could contribute to the early adoption of hydrogen as a universal energy vector.

Further information on the projects and their partners is available on the project web-sites www.roads2hy.com and www.hylights.org

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1. Introduction

This report is a deliverable of the Roads2HyCom project, a partnership of 29 stakeholder organisations supported by the European Commission Framework Six Programme. The project is studying technical and socio-economic issues associated with the use of Fuel Cells and Hydrogen in a sustainable energy economy. Within the project, several studies have been made related to the current and future cost structure to produce hydrogen. This report is one of three that looks at this topic, and focuses on some key elements of the current cost structure. Other reports on the topic are R2H2020PU (Cost Models for Current and Future Hydrogen Production) and R2H4003PU (Well to Tank Technology Pathways and Carbon Balance).

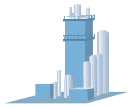
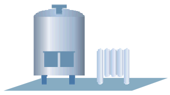
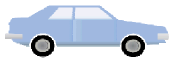
In principle, hydrogen can be produced from any primary energy source using a variety of different processes. The majority of hydrogen produced today is via proven and more ‘traditional’ means, i.e. steam methane reforming, coal gasification and electrolysis. In 2003, 48% of the global hydrogen demand was produced from natural gas, 30% from oil and off-gases from the chemical industry, 18% from coal and 4% from electrolysis *(Ref 7)*. These technologies form the basis of the industrial merchant hydrogen production landscape.

This report explores the cost base for these technologies today, based on information that is publicly available. It does not encompass broken down targets for future hydrogen cost, nor does it explore emerging technologies for hydrogen production, such as nuclear fusion and photo-electrochemical processes as viable cost information is simply not available.

It should be noted that in many cases cost data relating to production, distribution and transportation of hydrogen can be commercially sensitive. Therefore the authors have looked for previously published and validated data to support these propositions, which has proven to be extremely challenging.

The broad landscape open to provide hydrogen at an end use point is outlined in table 1 below:

Table 1: Different hydrogen pathways and end-uses

				
Energy source	**Hydrogen production**	**Distribution**	**Storage**	**End use**
• Natural gas • Coal, Oil • Biomass (crops, organic waste) • Renewable (wind, solar, marine, geo-thermal) • Nuclear	• Steam reforming • Gasification • Electrolysis • Thermolysis • Photolysis • Off-gas	• Pipelines • Compressed gas trailers • Cryogenic liquid tan-kers • Ship • Railway	• Metal tanks • Composite tanks • Metal hydrides • Chemical hydrides • Carbon structures	• Internal Combustion Engine (vehicle, stationary) • Fuel cell (vehicle, stationary, portable)

The components of the ‘hydrogen feedstock to dispensing’ value chain is outlined below and is comprised of what is necessary to produce, distribute and dispense hydrogen. For each step along the value chain there are a number of options available, such as for sourcing the necessary feedstock and energy to produce hydrogen, on how to transport the hydrogen, on how to store it at the use point and on how to prepare the hydrogen for use, i.e. for dispensing into vehicle tanks.

The elements of the value chain are examined in more detail below (figure 1).

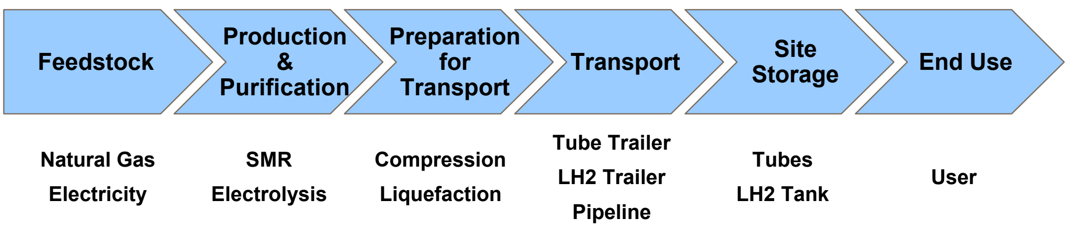


Figure 1: Hydrogen value chain

2. Feedstock

Steam reforming of **natural gas**, often referred to as steam methane reforming (SMR), is one of the most common methods of producing commercial bulk hydrogen as well as hydrogen used in the industrial synthesis of ammonia. It is also the least expensive method.

Other feeds, other than natural gas, for reformers are **liquid hydrocarbons** including LPG, naphtha and diesel. Natural gas is considered to be the most competitive feedstock during the introduction phase of the hydrogen economy.

Natural gas to large reformers would be supplied under high volume, long term contracts, at prices often significantly below spot prices. Natural gas supply to local, small-scale on-site reformers would come from the local gas distribution network. The price structure is different from large-scale supply.

Hydrogen can also be produced with **electricity** from the splitting of water through water electrolysis, often referred to as on-site electrolysis when produced at the end-user. Electricity is supplied by large producers like nuclear power plants or hydro power installations. Hydrogen production with electricity can also be used for regulating power on grids with a high share of intermittent renewable power. These aspects could provide certain benefits in terms of net costs of hydrogen produced; however, this is not accounted for in the cost picture in this report.

3. Production and Purification

3.1 SMR

Steam reforming of natural gas is widely used in industry today and the technology is mature. Hydrogen is produced by the SMR process in large centralized plants mainly owned by the chemical industry, which needs large amounts of hydrogen as internal process feed for the production of ammonia. Steam reforming involves the endothermic conversion of methane and water vapour into hydrogen and carbon monoxide. The heat is often supplied from the combustion of some of the methane feed-gas. The process typically occurs at temperatures of 700-850°C and pressures of 3-25 bar.

The product gas contains approximately 12% CO, which can be further converted to CO_2 and H_2 through the water-gas shift reaction. Two technologies are used to make the syngas reach the required level of purity.

- **Pressure Swing Adsorption**, is based on the selective adsorption of the undesirable components (mainly CO, CO_2, CH_4).
- **Methanization**, consists in the elimination of CO_2 and a catalytic transformation of CO into methane.

Table 2: Main steps for the steam methane reforming using either methanization or PSA

Step	Methanization	PSA
1 - Production of the syngas	$CH_4 + H_2O \leftrightarrow CO + 3H_2$ (1)	$CH_4 + H_2O \leftrightarrow CO + 3H_2$ (1) (remaining CH_4 3-8% vol)
2 - Conversion of CO into H_2 and CO_2 (water-gas shift unit)	2 step conversion $CO + H_2O \leftrightarrow CO_2 + H_2$ (2) (remaining CO 0.3 to 0.8% vol)	Single step conversion $CO + H_2O \leftrightarrow CO_2 + H_2$ (2) (remaining CO 1% or 2-3% vol)
3 – Phasing-out of CO_2		-
4 - Purification of H_2	Methanization of remaining CO et CO_2 $CO + 3H_2 \leftrightarrow CH_4 + H_2O$ (4) $CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O$ (5) (remaining CO and CO_2 < 10 vpm)	Selective adsorption
Comments - Purity of H_2 - Recuperation rate of H_2 (from the syngas)	 95 to 98% ~98%	 99.9% 85 to 90%

Note: The main impurities are methane, CO and CO_2. The PSA process gets a purer hydrogen but in a sensibly lower quantity when comparing to methanization. When considering that hydrogen lost during the purification step with PSA is then re-used as a fuel in the reactor instead of methane the difference between the yields of methanization and PSA remains very low.

Table 3: Economic data for the production of hydrogen from natural gas

Feedstock	Natural gas % (in volume)
H_2/CO	4.3
CH_4 CO CO_2 H_2 N_2	7.5 16.4 5.6 70.2 0.3

Table 4: Economic data for the production of hydrogen from natural gas

(Source: French Association for Hydrogen, based on IFP data)

Capacity	45,300 tons/year of hydrogen or 5,392 kg/h
Charge	Natural gas: approximately 900 GJ/h (in the reactor and as a fuel for auxiliary power)
Process	PSA (*recuperation rate of H_2= 88%)*
Investment	75 M€
Fixed costs (maintenance, workers, insurance and other costs)	330 €/h
Consumptions	- Electricity 1,500 kWh/h - High pressure steam neat production of 45 ton/h - Combustible (within the charge) - Catalyzer 66 €/h
Efficiency	H_2/natural gas = 72% based on LHV (H_2+neat steam)/(Natural gas + electricity) = 82% on LHV
CO_2 emissions	Approximately 9.3 tons of CO_2
Production cost (European basis)	Approximately 1.6€/kg (or 13.4€/GJ) for a 12% ROI and a project life reaching 15 years

Hypothesis : Natural gas: 7.25 €/GJ and Electricity: 66 €/MWh (18.37 €/GJ)

The formula linking the production cost of hydrogen to the price of natural gas, with a capital investment of 75 million euros is

$$P_{H2}\,(€/kg) = 0.187 \cdot P_{NG}(€/GJ) + 0.226$$

3.2 Electrolysis

Electrolysers are suitable for small scale on-site production of hydrogen and, like small-scale SMR, can be used in a market build-up phase allowing the use of the existing infrastructure for gas and power.

Alkaline electrolysers and PEM electrolysers are suited for stationary applications and are becoming available at operating pressures of up to 30 bar. Alkaline electrolysis is a mature technology, with a significant operating record in industrial applications that allows remote operation. While alkaline electrolysers are available in capacities between 1 and close to 500 Nm^3/h, PEM electrolysers are more limited to smaller capacities.

Alkaline electrolysers typically contain the main components shown in figure 2. The major R&D challenge for the future is to design and manufacture electrolyser equipment at lower costs with higher energy efficiency and larger turn-down ratios.

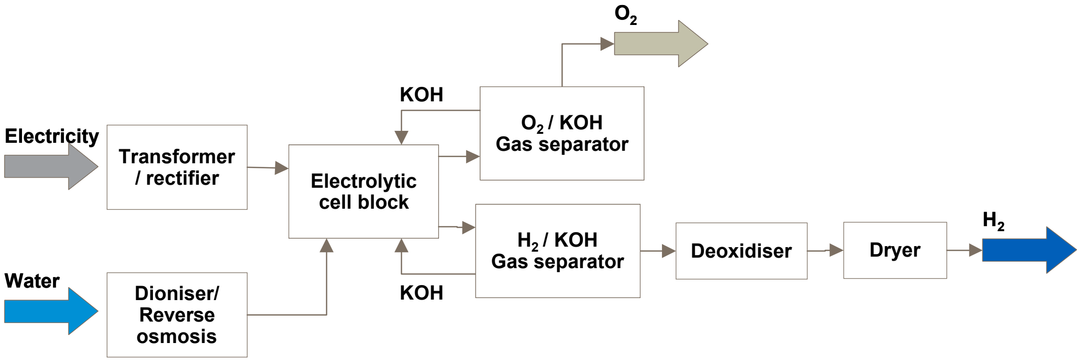


Figure 2: Process diagram of alkaline electrolysis [4]

In Table 5 and Table 6 two examples for hydrogen production costs with electrolysis can be seen. Both show the wide range range of costs depending on the exact conditions (size of plant, lifetime, electricity price, capacity factor). In conclusion, hydrogen from centralized electrolyis costs between 3.4 and 5.33 €/kg whereas hydrogen from on site electrolysis costs between 3.73 and 18.33 €/kg.

Table 5: Economic data for hydrogen production with electrolysis [15]

	Centralized electrolysis	On-site electrolysis	Units
Output pressure	3	2.6	MPa
Capacity	2400 72	360 10.8	kWh H_2/h kg $H_{2\ LHV}$/h
Electricity consumption	1.433	1.6	kWh/kWh $H_{2\ LHV}$
Investment	2.2	0.272[1]	M€
Maintenance	0.9	0.9	%Invest./yr
Work	0	0	€/yr
Lifetime	20	20	Years
capacity factor	6000	6000	hours/yr

Considering an electricity price of 66 €/MWh (18.37 €/GJ), the production cost of hydrogen from electrolysis is:

- **3.4 €/kg for centralized electrolysis**
- **3.73 €/kg[2] for on site electrolysis**

[1] The investment cost for the electrolyser seems very low, but as this data was compiled within a research project it will be taken as the lowest value.
[2] This price is taken as the lowest value as it was calculated with very low investment cost.

Table 6: Economic data for hydrogen production with electrolysis and wind energy. [16]

	Centralized electrolysis	On-site electrolysis	Units
Output pressure	0.1	1.2	MPa
Capacity	180,000 5,400	180 5.4	kWh H2/h kg H2 $_{LHV}$/h
Electricity consumption	1.39	1.43	kWh/kWh H2 $_{LHV}$
Investment	198	0.647	M€
Maintenance, miscellaneous costs	0.0056 €/ kWh H2 $_{LHV}$	16% Invest.	
Work	incl. in maintenance	5600	€/yr
Lifetime	10	10	years
capacity factor	6500	4000	hours/yr

Considering an electricity price (wind electricity) of 91 €/MWh (25.28 €/GJ), the production cost of hydrogen from electrolysis is:

- **5.33 €/kg for centralized electrolysis**
- **18.33 €/kg for on site electrolysis**

3.3 Summary production cost of hydrogen (Europe)

A summary of the current commercial cost of hydrogen production for the three pathways under consideration, and with the assumptions listed, is detailed below.

Table 7: Summary of hydrogen production costs

	Centralized SMR	Centralized electrolysis	On-site Electrolysis
Current production cost	1.6 €/kg	3.4 – 5.33 €/kg	3.73 – 18.33 €/kg

Assumptions : Natural gas: 7.25 €/GJ and Electricity: 66 €/MWh (18.37 €/GJ)

No CCS considered (as currently CCS is practically not used)

4. Prepare for Transport

Storage is used at the central production plant (in addition to the use point) to help meet time variations in hydrogen demand, and to assure a reliable hydrogen supply. For compressed gas delivery by tube trailer or pipeline, compression and gas storage are put in place at the production plant. For liquid hydrogen delivery, liquefaction and liquid hydrogen storage tanks are needed.

In order to move the gaseous product it is compressed and transported by road or where pipeline infrastructure exists by pipeline. Liquefied hydrogen is transported by liquid tanker.

4.1 Compression

Compression is required if storage is to be in a gaseous form. This is typically achieved by using a compressor, however it can involve pumped liquid being fed through a vaporizer.

The impact on the hydrogen cost for the compression element is made up of two main components: the cost of electricity required to operate the compressor and the capital and maintenance cost of the compressor itself.

A widely held assumption for the requirement of compression is 10-15% of the energy content of the hydrogen (see Figure 3).

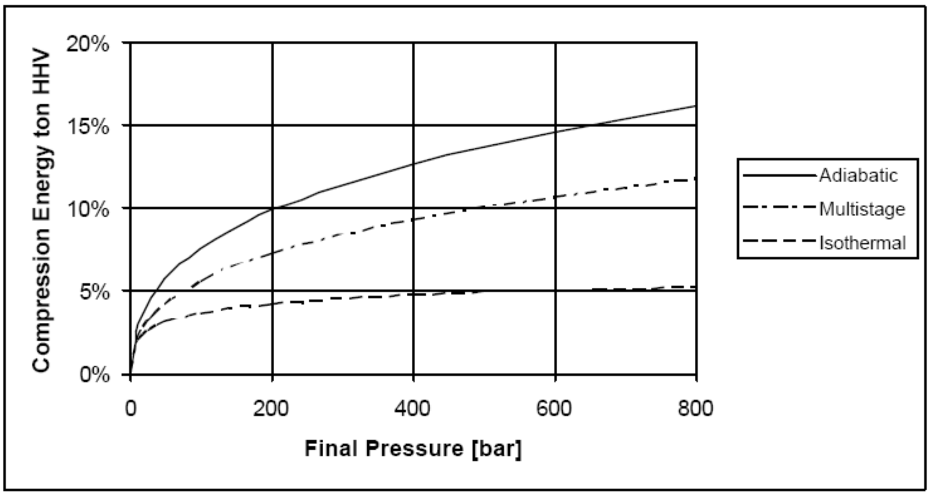


Figure 3: Energy consumption of the energy content of hydrogen during compression (HHV stands for Higher Heating Value)

For running costs, using figures of 10-15% of HHV (Higher Heating Value) required for compression, the electrical consumption can be estimated at between **0.3-0.45 €/kg[3].**

In terms of capital cost, a small compressor (~20 Nm^3/hr 300 bar) would typically cost between € 45,000 to € 90,000. This translates to a contribution to hydrogen cost between **0.63-1.26 €/kg**[4]. With economies of scale it may be possible to improve the capital cost of the compressor required.

Combining energy and capital components, this would give an approximate cost of **0.93–1.71 €/kg** for compression.

4.2 Liquefaction

Liquefaction is an expensive and energy consuming process. Between 30-40% of the thermal energy contained in the hydrogen is lost in the liquefaction process (see figure 4 and figure 5). The process of liquefaction does, however, increase the density of hydrogen by around 800 times compared to gaseous hydrogen at atmospheric pressure. Whereas liquid hydrogen can be stored at relatively low pressure, gaseous hydrogen would need to be highly compressed to contain the same amount of energy as liquid hydrogen. For example, at 700 bar the volume of gaseous hydrogen would still be around 1.7 times higher than liquid hydrogen.

However, there are issues with liquid hydrogen in that a percentage of the hydrogen is lost through "boil off" (lost vaporised hydrogen due to heat coming through the insulation) over time which impacts unit cost.

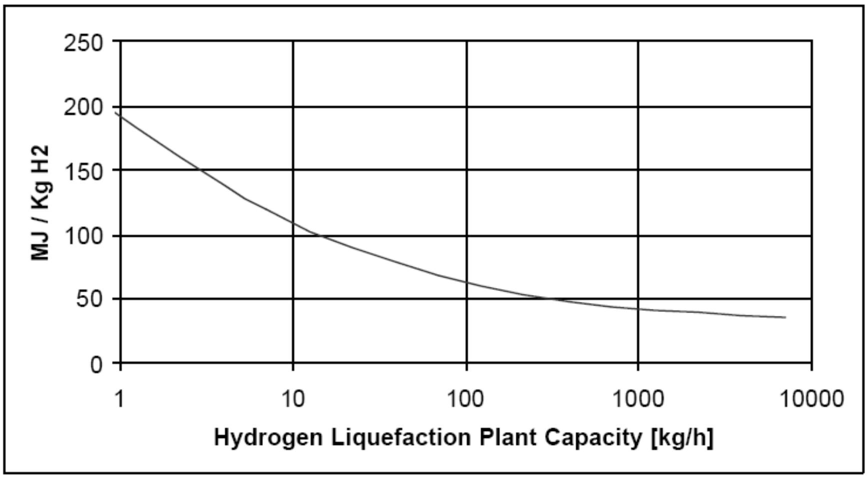


Figure 4: Energy requirements for liquefaction of hydrogen [3]

[3] Assuming 66 €/MWh for electricity price, Calorific value 12.10MJ/Nm^3, density 0.082824 kg/m^3, motor efficiency 0.85
[4] Assuming: 10 years life, running 12 hrs/day 360 days/year

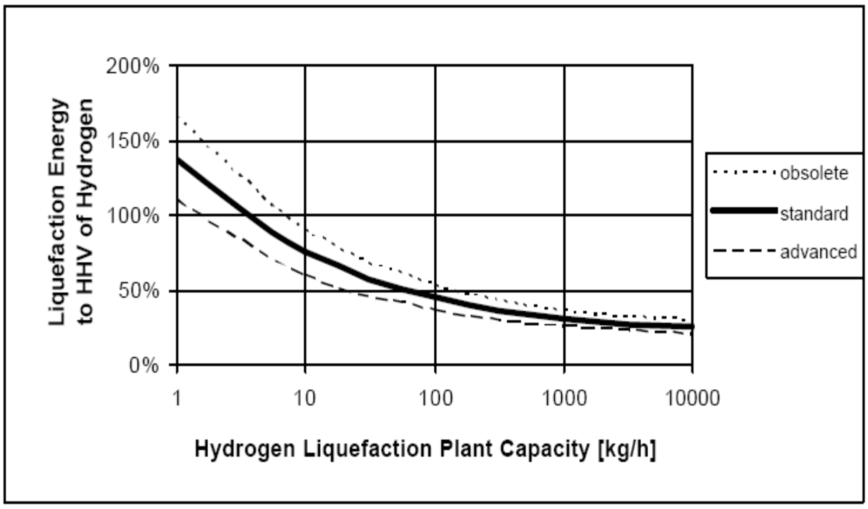


Figure 5: Energy requirements for liquefaction of hydrogen as percentage of the energy contained in hydrogen [3]

In terms of capital cost, RMW solutions [2] suggest that small to medium scale liquefiers would cost in the region of **0.49 €/kg – 1.07 €/kg** to build.

As liquefaction requires a very large primary energy input the cost is very sensitive to the cost of electricity.

5. Transport

The transport of hydrogen is characterized by the flow rate and transport distance. Hydrogen is transported either via pipeline or tube trailer for gaseous product or by liquid road tanker for liquid product. Existing hydrogen distribution mechanisms in place today vary in capacity, supply pressures and ultimately cost. Hydrogen cost associated with transport is a function of all of these variables and clearly distance from source and fuel costs are also important variables.

For short distances and small amounts, gaseous hydrogen delivery by tube trailer would be preferred. For medium amounts of hydrogen and long distances, liquid hydrogen tankers would be the most likely mode of transport. For large amounts of hydrogen, pipeline transmission is usually preferred if it is available.

5.1 Tube Trailer

Tube trailers typically have a capacity of 300 kg of gas [8], stored at high pressures of up to 200 bar [7]. For the future supply of hydrogen as a fuel, they are envisaged as being useful for low capacity users within urban areas requiring a supply of around 100 kg/day. These users could include fleet users or stations that are starting up in the use of hydrogen as a fuel. These customers would usually be relatively close to the hydrogen production plant in order to minimize the disproportionately high cost of carrying a small amount of product with a large truck.

The tube trailer could therefore be in competition with pipeline distribution as they are both supply methods that are more suited in urban areas. The advantage of the tube trailer being that it can be used for delivering hydrogen to a new user before they are connected to piped distribution. The costs below, however, are based on a relatively high market penetration.

The cost of tube trailer transport without reference to compression, is approximately **0.58 €/kg over a 100 km** distance from the city [6].

It is suggested that a tube trailer delivery including compression cost can cost as much as **2.22 €/kg** [6]. Other sources suggest **1.55 €/kg** based on a US market [5].

5.2 Tanker

Large tankers typically have a capacity of 400–4000 kg of hydrogen stored as a liquid. In the future, it is envisaged that these would be used for the large majority of filling stations, in particular those in rural areas far from a hydrogen generating facility. Liquid supply would however prove costly to customers requiring a small supply due to energy required for liquefaction.

It is suggested that a delivery by liquid tanker can cost **around 0.13 €/kg**, which is approximately a factor of 10 less than tube trailer [5]. This is roughly in line with the information given by the US DoE who suggest **0.15 €/kg** [6].

5.3 Pipeline

Many thousands of kilometres of hydrogen pipeline exist in various locations across the world. Typically these pipelines are 25-30 cm in diameter and usually operate at a pressure of 10-20 bar (pressures up to 100 bar may be used).

Pipeline supply can be effective when delivering hydrogen to a large number of high capacity users within a densely populated urban area. However, the energy required to pump hydrogen is considerable.

The transport cost of hydrogen with a pipeline network can be estimated from data for natural gas transportation expressed as a transportation of a given volume. This link has been proven by IFP within the building of a predictive tool for the transportation cost of hydrogen. The following table has been updated in 2007 for a 1000 km pipeline. It should be remembered that these calculations are viable only for large volumes (at least 5 Gm3/yr)

Table 8: Summary of hydrogen transport costs by pipelines [15]

Gm3/yr	$/1000 m3	€/kg (1$=0.73€)
5	30.1	0.244
10	22.6	0.183
20	17.5	0.142
30	16	0.130

6. On-Site Storage

Hydrogen can be stored at the point of use in a low pressure liquid hydrogen tank or, for gaseous hydrogen, in either a medium pressure or high pressure storage tank (cylinder packs or tube trailer). The selected mode of hydrogen storage would be dictated by volume and pressure requirements at the point of use.

Significant users of hydrogen, or those with stringent requirements on impurities, would typically have liquid product delivered, which may or may not be vaporised for the application. Liquid storage therefore can be used for both liquid and gaseous applications.

Again, several factors will have an impact on the cost of storage. Some of these are outlined in 9 below.

Table 9: Summary of hydrogen storage costs for stationary applications [1]

Storage System/ Size (GJ)	Specific TCI ($/GJ $_{capacity}$)	Storage Cost ($/GJ)
Compressed Gas		
Short term (1-3 days)		
131	9,008	4.21
147 (1)	16,600	33.00
13,100	2,992	1.99
20,300	2,285	1.84
130,600	1,726	1.53
Long term (30 days)		
3,900	3,235	36.93
391,900	1,028	12.34
3,919,000	580	7.35
Liquefied Hydrogen		
Short term (1-3 days)		
131	35,649	17.12
13,100	7,200	6.68
20,300	1,827	5.13
130,600	3,235	5.26
Long term (30 days)		
3,900	1,687	22.81
108,000	1,055	25.34
391,900	363	8.09
3.9 million	169	5.93
Metal Hydride		
Short term (1-3 days)		
131–130,600	4,191-18,372	2.89-7.46
Long term (30 days)		
3,900-3.9 million	18,372	205.31
Cryogenic Carbon (1-day)	4,270	26.63
Underground (1-day)	7-1,679	1.00-5.00

[1] This value is based on storage in pressurized tubes in a specific application and may not be appropriate for extrapolating (Taylor et al. 1986)

The cost of storing in the order of the magnitude of 1000 kg (141 GJ) of compressed gaseous hydrogen for a short time is **0.45 €/kg.** By comparison, storing the same amount of hydrogen in liquid form would cost approximately **1.83 €/kg.**

7. Summary

This report pulls together data currently available in the public domain on the cost in producing, storing and transporting hydrogen today. It has been very difficult to find, consolidate, and validate these data without using direct operational information, which is not in the public domain. Nevertheless, these findings are broadly in line with industry experience.

A summary of the costs for three production methods under consideration is outlined below in Table 10 and Figure 6 – of course with any data of this type, the sensitivity to raw material (oil, natural gas) and capital (steel) commodity prices has to be acknowledged. Further studies in the project have developed cost models that can account flexibly for these and other factors [17] and projected possible future scenarios [18]

Table 10: Summary of hydrogen cost for the three considered pathways ((Natural gas: 7.25 €/GJ and Electricity: 66 €/MWh (18.37 €/GJ))

	Central SMR	Centralized electrolysis	On-site Electrolysis
Current production cost (€/kg)	1.6	3.4 – 5.33	3.73 – 18.33
Compression (€/kg)	1	1	1
Transport (1000 km) (€/kg)	0.244	0.244	0.244
Storage (€/kg)	0.45	0.45	0.45
Total (€/kg)	**3.294**	**5.094 – 7.024**	**5.424 – 20.024**

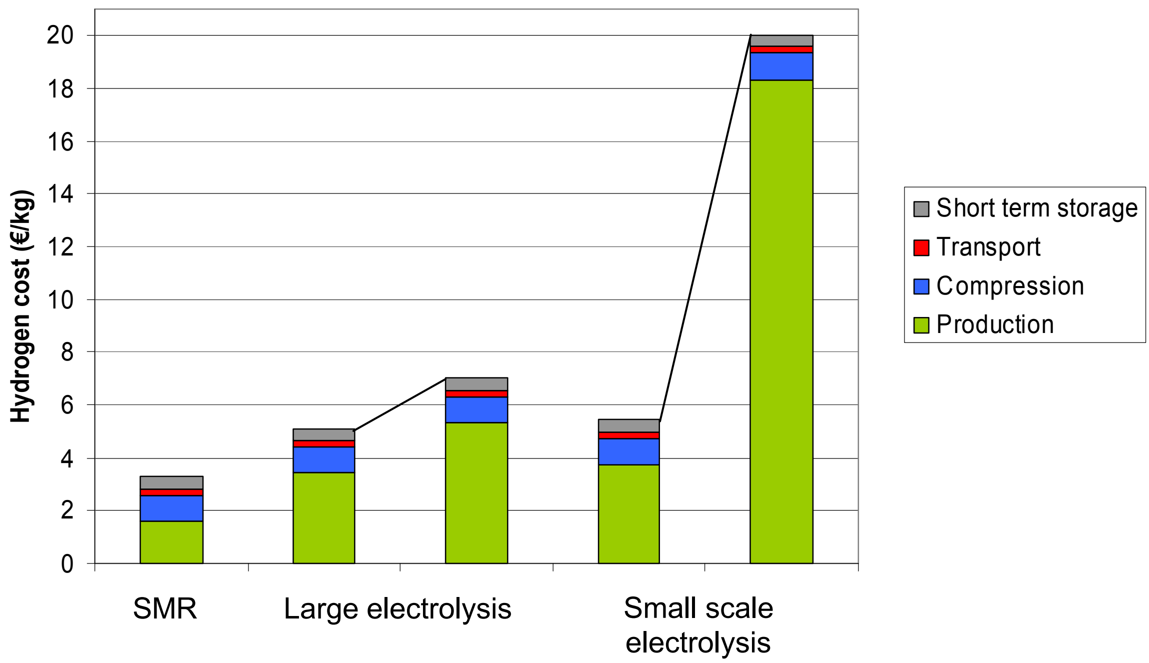


Figure 6: Summary of Hydrogen Cost Components (Natural gas: 7.25 €/GJ and Electricity: 66 €/MWh (18.37 €/GJ))

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