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LINKING DISTRIBUTED EUROPEAN HYDROGEN PRODUCTION SOURCES

PART I: Distribution Issues

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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

LINKING DISTRIBUTED EUROPEAN HYDROGEN PRODUCTION SOURCES

PART I: DISTRIBUTION ISSUES

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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 program. 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 question of primary energy sources to produce Hydrogen. This report is one of three that looks at the linking of those primary energy sources. The three reports are:

- Part 1: Distribution Issues (this document)
- Part 2: Electricity Grid Development Strategies and Constraints (R2H2014PU)
- Part 3: Hydrogen as a Storage Device (Document R2H2015PU)

The conclusions of these three reports are summarised in document R2H2012PU.

This report addresses the issue of the choice of relevant modes of transport and distribution of hydrogen. When is it worth to build a pipeline? When is it cheapest to deliver hydrogen in gaseous or liquid state? What about the possibility to use the Natural Gas (NG) network to distribute hydrogen?

Whatever the answer might be, it needs to consider the entire hydrogen supply chain, from production to end-users. Delivery of hydrogen cannot be decoupled from the level of centralisation of its production. This, however, was covered in previous reports based on global optimisation models for the costs of delivery of hydrogen in different time frames (see [HyWays 2007; DOE H2A]).

The objective of this report is to give techno-economical insights into the various modes of distribution of hydrogen, for today and the near future. Perspectives of evolution in the field of hydrogen delivery will be also introduced.

Chapter 2 deals with the distribution of pure hydrogen, whereas in chapter 3 the possibility to distribute hydrogen mixed with natural gas is investigated.

2. Pure hydrogen transport and distribution by pipe or truck

What is the best way to distribute hydrogen on a **point to point** delivery scheme from the H_2 production plant to the end-user? As pointed out earlier, this report does not take into account time frames or geographical parameters (density of population, delivery distances etc.), but purely gives a technical viewpoint. Three delivery modes are considered here:

- Trucks with compressed gaseous hydrogen stored in tanks (compressed gas trucks)
- Trucks with cryogenic liquid H_2 stored in tanks (cryogenic liquid trucks)
- Compressed gas pipelines

Work in this field was carried out by different teams including academic [Yang and Ogden 2007] or experts groups from the EU [Costsello, Tzimas et al. 2005] and USA [DOE H2A]. The following section provides costs assumptions for each delivery mode that can be used to determine the most costs-effective mode. The main conclusions on hydrogen delivery costs are then presented and illustrated by the results of a full costs analysis developed by Yang et al. from University of California, Davis [Yang and Ogden 2007].

2.1 Basic costs assumptions for the delivery modes

The total costs of each delivery mode consists of investment costs and operating costs. The latter depends on the local situation for production (fuel and electricity prices). The focus here is on the initial capital costs which can be an important factor in the choice of the delivery mode. Note that most capital costs data presented in recent studies [Yang and Ogden 2007] [Costsello, Tzimas et al. 2005; DOE H2A] were taken from reports and studies of the National Renewable Energy Laboratory (USA) and the University of California, Davis [Ogden 1999; Simbeck and Chang 2002].

2.1.1 Liquefaction costs

The main fraction of capital costs of a hydrogen liquefaction plant is given by the liquefier (40 M$ for a 30 000 kg/day capacity [Yang and Ogden 2007]). However when liquefaction is considered, it is important to keep in mind that electricity represents a high costs item also. Liquefaction is indeed only 65 % energy efficient and power costs account for 50-80 % of the liquefaction costs [Costsello, Tzimas et al. 2005]. The total liquefaction costs range from 0.055 to 0.78 $/kg of H_2 [Costsello, Tzimas et al. 2005] or are more than 1 $/kg of H_2 [DOE 2007] depending upon the literature source.

Liquefaction units and liquid storage have a large potential for economies of scale compared to compression stations of gas (comparison provided in the annex in the case of Yang et al [Yang and Ogden 2007]). On the other hand, the electricity input

for liquefaction is significant. Therefore only for large quantities of hydrogen to be stored, liquid hydrogen is being recommended.

2.1.2 Pipeline capital costs

Pipeline capital costs takes into account pipe capital costs and compressor capital costs. For the same quantity of energy transported, friction losses in pipelines with hydrogen are much lower than for in those with natural gas. As a consequence there should be no need of compressor stations along the pipelines (data from Gaz de France and Air Liquide). This could significantly reduce the compressor capital costs.

The total costs of pipeline for high pressure transport (given by unit of length) depends on (WGP, 2008) :

- Materials, accounting for 15-35% of the total costs depending on the diameter of the pipe
- Installation (including labour), accounting for 40-50% of the total costs
- Right of ways, corresponding to the land costs for installing pipelines, usually a small fraction of the total costs
- Miscellaneous costs which include surveys, engineering, supervision, interest, administration and overheads, contingencies and allowance for funds used during construction (20-30% of the total costs)

The total costs vary strongly with the location; offshore pipelines are of course more expensive than onshore/inland pipelines but the costs of the latter can be very high in urban areas. Different studies roughly estimate pipeline capital costs between 300000 to 1500000 $/km depending on its location and its size (diameter, length). The pipeline costs increase with the diameter of the pipe, as does the materials costs increases with diameter. Some analytical formulas for capital costs estimations based on correlations with natural gas pipeline costs and function of pipe diameter and in some case pipeline length have been reported in the literature [Parker 2004; Costsello, Tzimas et al. 2005; Yang and Ogden 2007]. The data reported by Costsello et al. proposed a correction factor for hydrogen services, which ranges between 1.4-2.0 depending on pipe diameter and installation technology [Costsello, Tzimas et al. 2005]. Parker proposes another analysis leading to a lower investment costs increase for hydrogen pipelines [Parker 2004]. Indeed based on Parker's results and the conclusions of the experts Working Group "Hydrogen Pipeline" of the DOE H2A program, the hydrogen pipeline capital costs were assumed to be 10% higher than those for natural gas [DOE 2005] (for a given diameter). Figure 1 displays the estimated costs of installed pipelines per km as a function of the pipe diameter.

Other costs (e.g. operating costs) used in Yang et al. case [Yang and Ogden 2007] are reported for information in the Annex.

Pipelines represent a high initial investment. However, as the pipeline´s capacity increase is proportional to $D^{2.5}$, the costs of hydrogen transported decreases with increasing pipe diameter. Together with economy of scale effects this makes

pipelines a good choice for long-distance, large diameter transmission for high flow and high energy demand [Costsello, Tzimas et al. 2005].

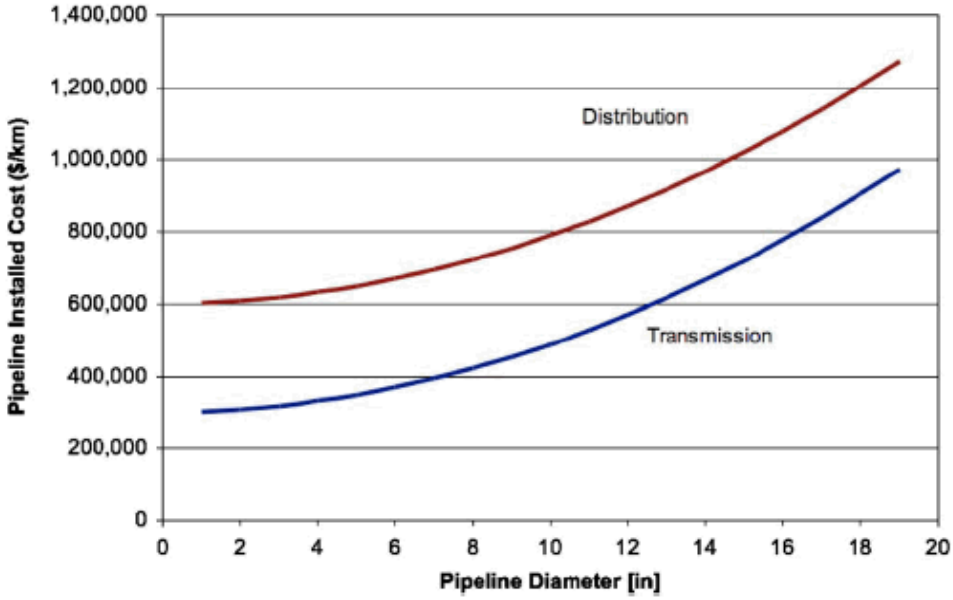


Figure 1: Pipeline model installed costs ($/mile) dependence on pipeline diameter [Yang and Ogden 2007], based on [Parker 2004].

The total costs installed includes material costs, installation costs, right of way and miscellaneous costs. The gap between transmission (long-distance transport) and distribution (local network) accounts for a mean difference in terms of right of way and installation costs, but can vary greatly with location.

2.1.3 Truck capital costs for compressed gas or cryogenic liquid delivery

Seamless steel vessels for compressed gas delivery by trailer are currently the most common delivery mode for short distances (<200 km) and small quantities (< 300 kg). Single cylinders, multi-cylinder pallets or tube trailer are commercially available [Costsello, Tzimas et al. 2005]. In the scope of this study, we will only focus on tube trailer.

Table 1 lists the capital costs assumptions for compressed gas or cryogenic liquid delivery by truck.

Table 1: Specific costs assumptions for compressed gas or cryogenic liquid delivery by truck [Costsello, Tzimas et al. 2005; Yang and Ogden 2007]

	Compressed gas [Yang and Ogden 2007]	**Cryogenic liquid** [Yang and Ogden 2007] [Costsello, Tzimas et al. 2005]
Total truck capacity (kg H_2)	300 kg*	4000
Truck P max/min	160 atm/30 atm	/
H_2 boil off	/	0.3% / day
Capital costs		
Tube trailer costs ($)	150 000	650 000 [Yang and Ogden 2007]/350 000 [Costsello, Tzimas et al. 2005]
Undercarriage costs ($)	60 000	60 000
Cab costs ($)	90 000	90 000

*the net capacity is reduced due to the minimum gas pressure in tanks to ~250 kg.

The main costs factors in compressed gas truck delivery are capital costs for trucks and trailers, operation and maintenance including drivers' labour and fuel costs. The capital investment is low for small volumes of H_2 but it does not benefit from economies of scale with increasing demand and the costs increase linear with delivery distance.

On the other hand, for cryogenic liquid truck delivery liquefaction equipment and electricity input for liquefaction (accounting for 33% of H_2 energy content) are the largest costs factor. However, significant cost reductions due to scaling effects of liquefaction equipment are possible. The number of liquid trucks will be dependent on the hydrogen demand and the localisation of the liquefaction point. In addition, the capacity of delivery is about 10 times larger than the one of gas truck trailers. As a consequence the truck capital costs and operating costs (fuel, labour) are much smaller.

2.2 Comparisons between point-to-point delivery modes

Based on previous data, the costs of hydrogen point-to-point delivery can be calculated as a function of the distance and the flow rate.

Figure 2 displays an example of transmission costs for the three delivery modes for different flow rates and transport distances. The costs varies from less than 0.4 to roughly 4.5 $/kg of H_2 delivered, which roughly corresponds to 0.05 to 0.50 €/Nm^3 of H_2 delivered. This example clearly illustrates the strong relation of gaseous truck delivery costs and distance. For liquid hydrogen, the costs depends largely upon the flow rate, due to economy of scale for the liquefaction equipment, but is rather independent of distance because of the higher capacity of the trucks. For pipelines, the pipeline costs capital is the main contributor and the costs scales strongly on distance and flow rate. In this calculation, the inlet pressure was 70 bar. Yet higher pressures can be considered for large scale transmission of hydrogen.

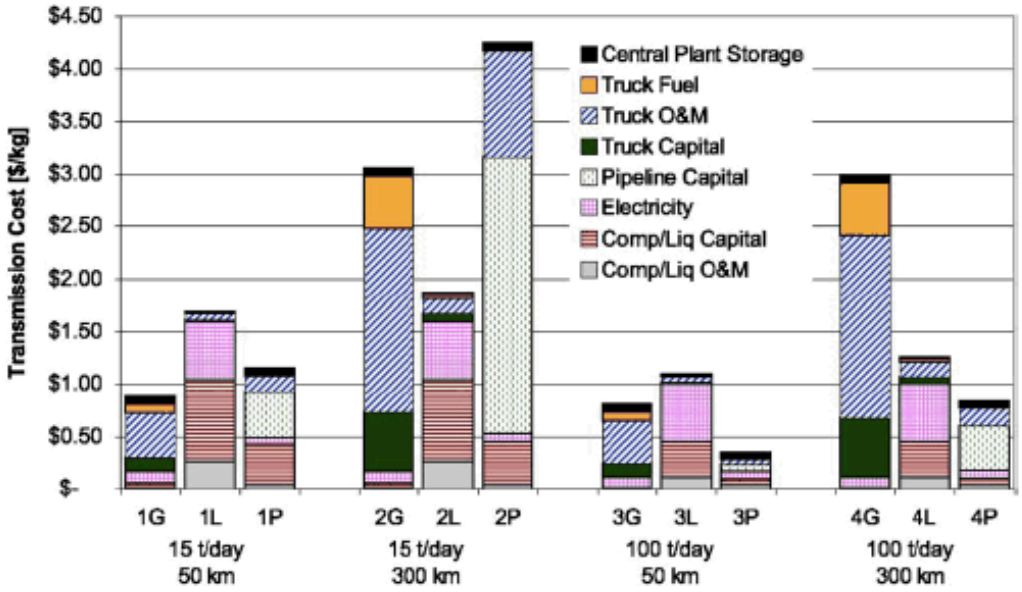


Figure 2- Transmission costs ($/kg) for hydrogen as a function of flow and distance for the 3 delivery modes and different scenarios [Yang and Ogden 2007]. (G: gastruck; L : Liquid truck; P: Pipeline).

The lowest costs hydrogen delivery modes have been determined from the same study for distances in the range 0-500 km and flow rates in the range 2-100 t/day (Figure 3).

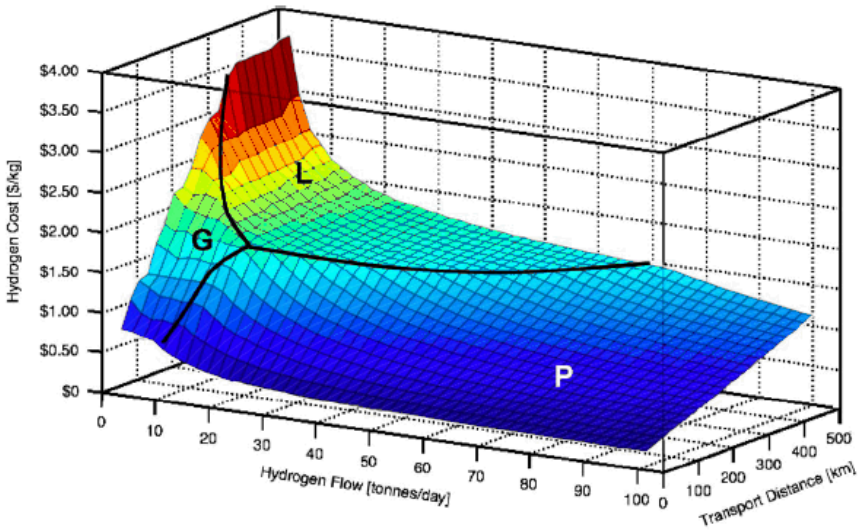


Figure 3- Minimum hydrogen transmission costs as a function of H_2 flow and transport distance [Yang and Ogden 2007]

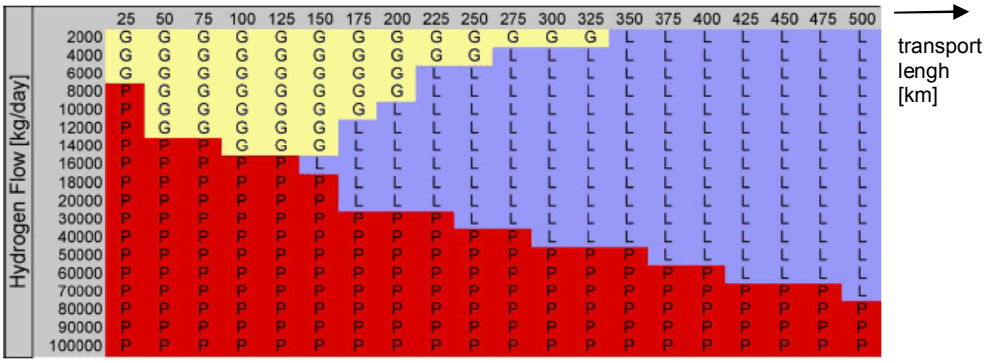


Figure 4- Mode map describing the lowest costs hydrogen delivery mode as a function of hydrogen flow and transport distance. G, L and P stands for gas truck, liquid truck and gas pipeline, respectively. [Yang and Ogden 2007]

Even if the figures and thresholds of switch from one transport mode to another may vary following the authors, the general trends of this kind of analysis remain (see Table 2). They reveal that [Costsello, Tzimas et al. 2005; DOE 2007; Yang and Ogden 2007]:

- For short distances and small amounts of hydrogen, **gas trucks** are preferred. Gas truck delivery has low capital investments for small H2 quantities as compared to the other delivery modes. The main costs factors are capital costs, operation and maintenance (including labour and fuel) as a consequence, it does not benefit of economy of scale and it can be very sensitive to the economical and political environment (labour and fuel costs and CO_2 emission coming from the fuel truck combustion).

- For medium amounts of hydrogen and long distances, **liquid H_2 trucks** delivery is preferred. There is significant economy of scale associated with the liquefaction equipment but this mode of delivery relies on the price of electricity required for liquefaction and on the decision to install new liquefaction facilities. The liquid truck capacity being much higher than for compressed gas truck, this mode of delivery is less dependent upon the transport distance

- For large amounts of H_2, **pipeline** delivery is preferred. The pipeline capital costs is the largest factor and it increases strongly with distance and flow rates. Costs also increase with the pipeline diameter but as a pipeline´s capacity increase is proportional to $D^{2.5}$, the costs of hydrogen transported decreases rapidly with increasing pipe diameter.

Yet a strong limitation has to be kept in mind when considering the previous calculations. Indeed, the following key assumptions are underlying these studies:

- although there is no detailed cost comparison available with on-site production, HyWays (HyWays 2007) results expect a competition between on-site production and LH2 delivery for remote sites.
- All hydrogen demand is for gaseous hydrogen. If there is some demand for liquid hydrogen (for example for car applications), the step of liquefaction is compulsory and the transport in liquid form is competitive in a more extended range. For example, the HyWays project has considered scenario with a hydrogen demand up to 20% in liquid form.
- It does not take into account the environmental life cycle assessments
- We do not consider the security problems (strict regulations, accidents, traffic jam, etc.) of road transport in the case of high amount if hydrogen delivered by liquid and gas trucks.

Table 2. Comparison of compressed gas truck, cryogenic liquid truck and compressed gas pipeline delivery of hydrogen

Delivery media	Compressed gas truck	Cryogenic liquid truck	Compressed gas pipeline
Flow range	Low	Medium	Large
Distance range	Short	Medium-Long	All distances
Advantage	Low capital investment for small amounts of H_2	High delivery capacity of trucks	Low costs when fully used
Limitation	High operation costs, low truck capacity	High liquefaction costs (equipment + energy)	High capital costs especially in urban area
Economy of scale	No	Liquefaction equipment	Strong on distance and flow rate

2.3 Perspectives of evolution for hydrogen pipelines

The studies on the understanding and optimization of the H_2 delivery infrastructure underline the limitations induced by the capital costs (pipeline, liquefaction equipment) and the capacity (limitation of tank pressure in trailers) of the delivery mode. Uncertainties in the market development of hydrogen increase the risks associated with investing in a pipeline network. The main costs concern :

- Pipeline installation, including joining and welding issues
- Pipeline materials which can present steel embrittlement in presence of hydrogen [Costsello, Tzimas et al. 2005] and are sensitive to corrosion

2.3.1 Steel pipelines

Industrial hydrogen pipelines made from steels such as X42 or X52 can be operated at pressures up to 100 bar. Their diameters are up to 20-30 cm. One question is to know whether the current technology could support the deployment of a large scale network for hydrogen energy. A partial answer to this question can be derived from the following rough estimate:

- The HyWays Infrastructure deliverable (HyWays, 2007) gives estimations of fuelling stations for different countries, the transport applications accounting for the main share of hydrogen demand. If we consider the number of large fuelling stations (typically highways stations) after 2030 for a high penetration scenario in Germany, we get a demand of about 800 000 Nm^3/h of hydrogen.

- In order to work with a conservative hypothesis, we assume an highly centralised production infrastructure, with only 2 large scale production sites, roughly 400 000 Nm^3/h for each.

- The current tools used to engineer hydrogen pipelines allow to calculate that using the highest diameters and pressures (150 bar) compatible with the current specifications of hydrogen pipe engineering, the necessary transport speed in the pipe stays below the maximum specified limit.

Therefore the construction of a pipeline network dimensioned for hydrogen energy does not raise any problem of feasibility from the point of view of dimensioning of the pipes.

However, the previous estimation does not mean that the development of such an extended network is free from difficulties. In fact, the operating conditions of a hydrogen energy pipeline would be different from an industrial hydrogen pipeline :

- Firstly, today's hydrogen pipelines are operated at a constant pressure, without pressure cycles or swings. On the contrary, hydrogen energy pipelines would have to bear variations of pressure (as it is the case for NG pipelines). This is a concern because of the phenomenon of hydrogen embrittlement of steels. Hydrogen embrittlement results in a loss of ductility of steel under strain and an easier crack propagation. These effects have been studied for long, and are taken into account both by specifications for the steels used to build pipelines and adapted rules of design. Further investigations in this field are under way in various national research programmes (eg. USA, France).

- Secondly, the deployment of a distribution grid in urbanized areas would make the hydrogen pipelines much more exposed to external injuries, as it is the case for natural gas today. This argument can also be applied to trucking which can be heavily exposed to the risk of traffic accidents.

Altogether, addressing the safety issues related to distribution networks of hydrogen require careful investigation on the topics discussed above. As with the natural gas networks in the 1950's the security regulations will evolve in parallel to the development of future hydrogen networks.

Moreover, while industry experts agree that the costs to build hydrogen pipelines are not significantly more than the costs to build natural pipelines today, this high investment still represents a significant barrier to the deployment of an extended hydrogen grid. The US Hydrogen Delivery Targets propose an "optimistic" capital costs target of 490 000 $/mile (or 306 000 $/km) in 2017 for a 16'' pipeline, from the hypothesis of 700 000 $/mile (or 435 000 $/km) in 2005. The efforts to reduce these costs are expected mainly to come from:

- Improved welding and joining techniques
- Improvement of the understanding of the hydrogen embrittlement in the conditions of use of the hydrogen pipelines, and especially in the Heat Affected Zone of the welding:
  - To develop new high-strength steels (although the impact in the total costs may be limited since the diameter of hydrogen pipelines is smaller than that of NG pipelines)
  - To avoid over conservative specifications of hydrogen pipelines

2.3.2 New polymeric and composites pipelines

Current R&D investigations are interested in the development of polymeric and composite-polymer based materials for pipes as they present the advantages of being:

- Lightweight compared to steel which makes them easier to handle and means less energy for transportation
- Non-sensitive to corrosion (no need for a cathodic protection)
- Non-sensitive to hydrogen embrittlement but depending on the material H_2 permeation can be high
- Flexible which enables installation of long pipe sections (several hundred meters while it was limited to a few tens meter for steel) or change of direction of the pipeline with a single piece of pipe
- Easier to join and weld

2.3.3 Polymeric materials for pipes

Polymeric pipes currently used are made of polyethylene and have a pressure rating limited to 10 bar [1995]. They are used in the natural gas distribution network. However the hydrogen permeability rate is too high to allow their use for hydrogen transportation [Jasionowski and Huang 1981]. In addition a pressure rating of 10 bar may be too low for the application. Polymers such as polyamide (and more particularly polyamide-12) present a better choice as the permeability of hydrogen is significantly reduced and its thermo-mechanical properties allow pipes to sustain a 20 bar operating pressure (ISO rating under progress) [Lohmar 2006].

Polyamide pipes appear as a feasible alternative to steel at relatively low operating pressure, providing that the costs are not too high as compared to steel. Figure 5 provides a comparison of the costs of (by Degussa, a polyamide pipe manufacturer [Lohmar 2006]):

- Steel pipes with a diameter of 100 mm, run at 20 bar, carrying 3000 Nm^3/h NG
- Polyamide-12 with a diameter of 110 mm, run at 20 bar, carrying 3000 Nm^3/h NG
- Polyethylene, with a diameter of 140 mm, run at 10 bar, carrying 3000 Nm^3/h NG.

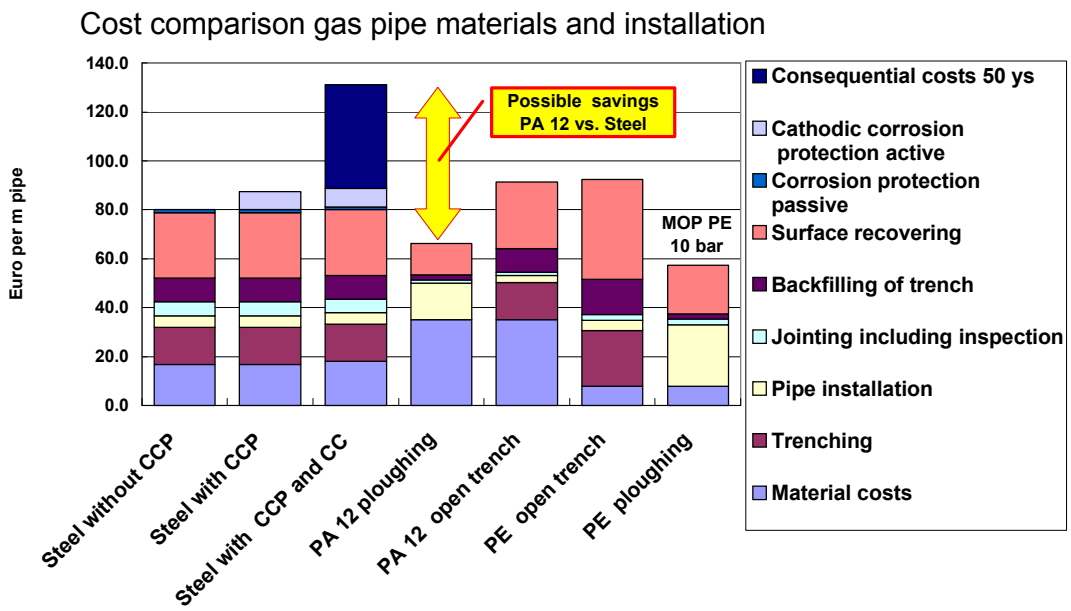


Figure 5. Costs comparison of the contributions to the overall installation and operation costs of gas pipelines made of steel, polyamide-12, polyethylene.

The specific costs are taken from the actual situation in Germany. The new developed polyamide 12 gas pipe compound price was fixed of 10 Euro per kg for this calculation [Lohmar 2006].

The diagram of Figure 5 reveals that polymer pipes can be an alternative to steel in comparable running conditions thanks to savings in installation and maintenance costs. For polymer pipes, there is indeed no need for protection against corrosion; which is usually expensive; the pipes are supplied coiled up to 400 m in one piece (see Figure 6) which can be installed continuously by ploughing or drilling technologies. Ploughing is a costs saving procedure where a trench is made, the pipe inserted and the trench refilled simultaneously. This contrasts strongly with the installation of steel pipes of much smaller length (a few tens meter) which are welded in open trenches. However, material supply can represent a high ratio of the total costs (Figure 5).

Figure 6. 60 m coil of Degussa polyamide-12 [Lohmar 2006]

2.3.4 Composite materials for pipes

Pipes in composite materials are composed of a thermoplastic liner (mainly polyethylene) wrapped with high strength fibres (most commonly aramid fibres) then coated with a thermoplastic layer. This last layer protects from environmental influences and helps to retain the wrapping mainly responsible for the mechanical properties.

Compared to simple plastic pipes, wrapping with aramid fibres allows a pressure rating of at least 100 bar [Smith, Frame et al. 2007] [Wolters, Wessing et al. 2006]. These reinforced plastic pipes are already used for natural gas or crude oil distribution in the middle-east of the USA [Wolters, Wessing et al. 2006] and their development for H_2 delivery is currently part of US DOE R&D efforts [Smith, Frame et al. 2007]. The DOE has funded a hydrogen pipeline working group that involved the main actors in gas and fuel transportation.

According to literature, Fibre Reinforced Plastic (FRP) pipes could be a cost-effective option when long lengths of pipes are to be installed (ca. 200 to 300 meters), using ploughing techniques which offset the raw material prices (mainly depending upon the amount of fibre) [Wolters, Wessing et al. 2006]. As part of the DOE program on hydrogen pipelines, the costs of installation of 4.5” (i.e. 114.3 mm) diameter FRP 100 bar rated pipes in a urban area were compared to the installation of a 16” (406.4 mm) diameter steel pipe (Table 3). This simulation reveals that FRP seems to be a good alternative to steel in that case. However the manufacturing process does not allow to get plastic pipes with diameters as high as steel pipes (100 and 150 mm are most common diameter [Wolters, Wessing et al. 2006]).

Table 3. Costs comparison between FRP and steel pipes for a city of 200 000 people [Smith, Frame et al. 2007]

FRP pipelines installed ($/km)	Estimated right of ways and permitting costs ($/km)	Total investment ($/km)	16-inch steel pipeline ($/km)
206 000 – 215 000	155 000	361 000 – 370 000	395 000

Further developments are still needed on the connection technology, mechanical tests, liner materials (assessment of H_2 permeability) and field evaluation with hydrogen.

2.3.5 Socio-economic aspects and infrastructure build-up

Albeit the economic factors presented above the demand of hydrogen at the end-user does not necessarily follow linear patterns and growth. The project HyWays (HyWays 2007) developed infrastructure build-up scenarios for fuelling stations which illustrate the need for hydrogen supply for different demand growth rates, depending on the variable market penetration of transport applications (Figure 7)

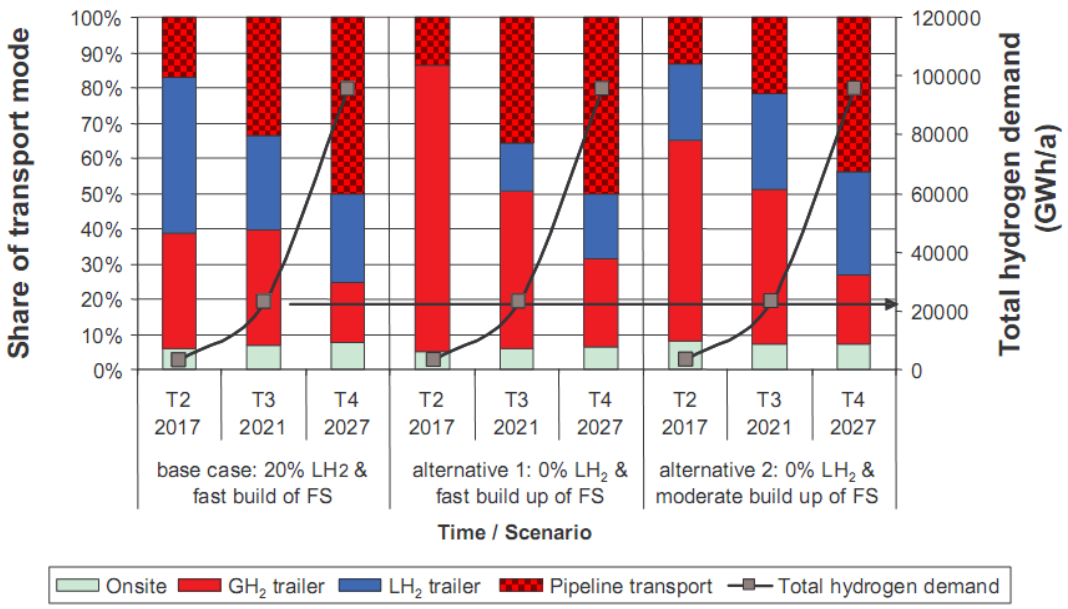


Figure 7: Share of hydrogen delivery options of time, following three scenarios with differing demand for hydrogen, resulting from an increase of the number of cars using hydrogen.

T2 assumes a market penetration with 500 000 cars by 2017 and a ~25% share of population with local hydrogen access

T3 with 4 million cars by 2021 with a ~50% share to hydrogen access

T4 with 16 million cars by 2027 and a ~85% share of population with local hydrogen access

(HyWays 2007)

As laid out in previous chapters, with growing demand the mode of transport for hydrogen changes depending on volume and distance. However, as can be seen in Figure 7, preferences of the market demand for a certain form of supply (e.g. LH2 for transport applications) have a strong impact on the mode of supply regardless of static parameters like volume and distance, or sole economic considerations. In the base case, 20% of the hydrogen demand is expected to be liquid for cars that can only be fuelled with LH2.

In this situation it is necessary to provide enough LH2 in a certain location from the very first day (since it cannot be liquefied on-site from CGH2), whereas a situation in which there is no need for liquid fuelling draws a different picture. With no LH2 requested at the pumps, CGH2 would suffice in the early transition phase. The use of liquid supply for the station - then not based on customer demand at the pump but on economic reasons due to the overall hydrogen consumption (and vaposised on-site) - can come in later when demand figures justify this supply route.

Also, there might be a limited supply capacity for a certain mode of transport. Steinberger-Wilckens and Trümper (2007) showed in the context of a large assessment of European hydrogen infrastructrure that, for instance, at present the capacity of liquefaction capacity is still low and thus limited.

Further, the HyWays study shows that end-user distribution nodes like fuelling stations have a need to compensate fluctuations, usually addressed by building overcapacities. This means that at a given time they would need to pay for a mode of supply which probably is not the most economical at that stage, but could become more economical with growing (and expected) demand in the future. Alternatively, there could be a split of supply modes, for example LH2 base supply and added CGH.

3. Using the existing natural gas network to transport hydrogen

3.1 The existing natural gas network

According to the European Union of the Natural Gas Industry, at the end of 2003 there were approximately 1850000 km of pipelines in Europe (EU25), of which almost 90% are for distribution. While North America, Europe, Russia are expected to remain, by 2030, the largest world natural gas consumers, the demand is expected to grow very rapidly in emerging economies; China, for instance, is expected to have an average demand growth rate of 5.5% per year up to 2030.

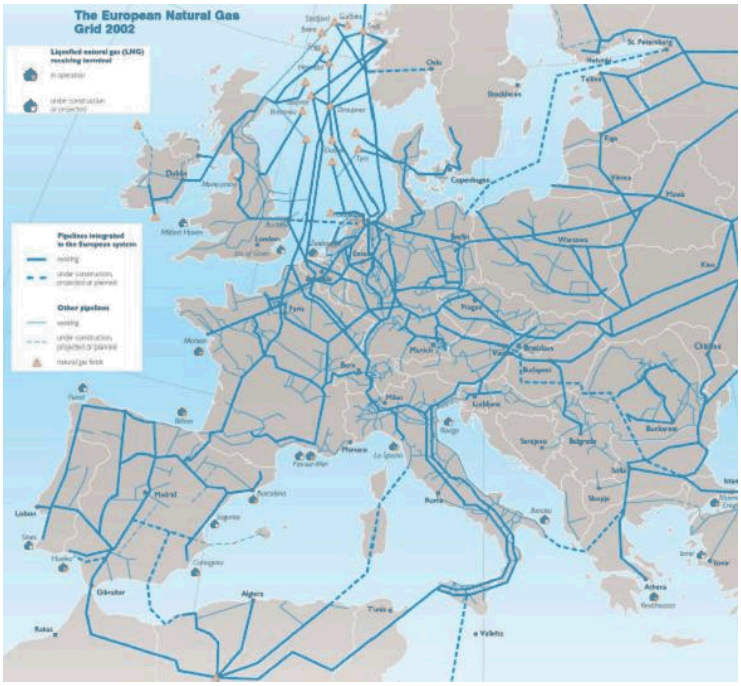
Several hundreds of thousands of both large-size transportation and mid/small-size distribution lines have been constructed over the last 30 years all over the world, to match with the increase in natural gas consumption. Over this period, the proportion between transmission and distribution lines depended both on degree of maturity of the market and on the import / export balance.

In the USA the total natural gas consumption has increased by 5-10% from the early 1970s. At the end of 2002, domestic production accounted for more than 80% of consumption (it was more than 95% in 1973). The distribution network has developed much more (up 50% in 2002 compared to 1984) than the length of transmission lines (up 7% over the same period).

In the 1960s in Europe, the signature of long-term natural gas contracts allowed the development of large infrastructure networks across Europe from the producing countries to the consuming countries. In the 1990s, taking into account the favourable evolution of the situation in Central and Eastern Europe, various projects for the construction of pipelines, such as that of the Yamal gas pipeline, could be started.

The natural gas consumption has increased threefold (Europe OECD Countries) over the same period and a strong dependency on imports from Siberia and North Africa (covering more than 65% of the total consumption in 2002) led to the development of both major long-distance transport axes and a wide distribution network in Europe, as it is shown figure 8.

situation 1970



situation 2002

Figure 8: European natural gas high transport grid in 1970 and 2002 [Source: Eurogas]

The natural gas supply chain and the natural gas transporting network between the natural gas deposits and the consumer are quite complex. After the gas has been extracted, so-called “trunk lines” are connected with pipeline head stations. The natural gas is then pumped into long distance pipelines (transportation lines) and sent to the take-off stations for the consumers. From there the gas is further transported to the control station of the regional distribution system. It then finally goes to industrial customers and households.

Pipeline pressures, diameters and materials used at the different stages of transport vary considerably from country to country, with minor differences also within national systems, depending on the supplier (Table 4).

Table 4- Pipelines pressures, diameters and materials at the different stages of transport for NG

Transport Stage	Pressure (Bar)	Diameter range (cm)	Materials used
To head station	70 - 100	40 - 150	Low-alloy, High strength steels
Long distance	60 - 90	50 - 130	Low-alloy, High strength steels
Local/regional	08 - 40	7.5 - 30	Low-alloy, Low-carbon steel
Customer	0.05 – 0.10	2.5 – 5.0	Low-alloy, Low-carbon steel, PVC*, PE**

*PVC = Poly-Vinyl-Chloride, **PE = Polyéthylène

For long distances and to transport a sufficient amount of gas, the pipeline pressure must be maintained at approximately 80-90 bar. Powerful compressor plants are installed, in theory, every 150 km (27 compression stations are present on 31500 km of pipelines on France GRT gas grid). Plastic pipes are largely used in many countries for gas distribution at customers level and low pressures. Pipelines for oil and natural gas are typically constructed from low-carbon or low-alloy steels. These steels are primarily composed of iron (98-99% weight), carbon (up to 0.30% weight) and manganese (0.30-1.5% weight), with small amounts of other alloying elements such as molybdenum, vanadium and titanium. This combines economical affordability with an adequate range of engineering properties, such as strength, toughness, ductility and weld ability.

3.2 Challenges faced upon transporting hydrogen in the natural gas network

3.2.1 Framework

The use of the natural gas pipeline network to deliver pure hydrogen or mixed (natural gas/hydrogen gas) gas, without significant modification, may provide major costs / schedule benefits in the transition to a hydrogen energy economy.

Alongside studies carried out in the recent past [Oney, Veziroglu et al. 1994; Amos and Laboratory 1998; Parker 2004], both European and national projects are currently under way to assess the feasibility of transporting hydrogen through the existing gas networks, either mixed with natural gas or as a pure gas. Prime examples in this field are NATURALHY[1], a project launched in 2004, co-financed by the EC under the Sixth Framework Programme for Research and Development, and the activities of the Nordic H_2 Program[2] and the EET Dutch program[3] for testing materials, components and connections from the natural gas distribution grid in pure hydrogen. Furthermore, the development of completely new hydrogen pipelines networks can try to incorporate some of the lessons learned from existing natural gas infrastructures. On the other hand, hydrogen transmission through pipelines will be different in many respects from that of natural gas. This is not only because of the different physical and chemical properties of the fluid transported and the resulting consequences on engineering and economics, but also because the hydrogen supply may develop according to a different economic pattern. Despite this, the gas and oil industry has already experienced the transformation of existing pipelines from oil (Air Liquide in Texas; [IPC 2006]) and natural gas [Statoil, Norway 1999] to hydrogen transportation.

The level of branching, i.e. the depth of penetration of a distribution infrastructure, would very much depend not only on the extent but also on the kind of demand, and the way this evolves. In the short to medium term, the use of hydrogen as an alternative vehicle fuel would probably imply distribution from a production site to a distribution centre, from where the hydrogen could be trucked to individual refuelling stations. With increasing demand, this scenario may evolve into one with hydrogen distribution via pipelines down to major individual dispensing facilities. If hydrogen is used also for stationary applications, as a replacement of both liquid fuels and natural gas, then the relevant infrastructure would have to follow the same pattern of the existing natural gas distribution network.

1 http://www.naturalhy.net/start.htm
2 http://www.h2foresight.info/
3 http://www.senternovem.nl/EET/english.asp

3.2.2 Material compatibility

The introduction of hydrogen in natural gas dedicated pipelines can have many consequences on durability, maintenance and safety of material components. The many degradation problems, caused by hydrogen to material properties, have to be considered before introducing hydrogen into the existing natural gas network. Also, existing pipelines and especially compressor stations are optimized to work under a certain range of conditions, including gas composition. Most machines used in pipeline applications are multi-stage centrifugal compressors that have difficulties in accommodating wide changes in the physical properties of the transported gas. Piping seals, valves, heat exchangers and meters would also have to be modified or replaced if hydrogen was transported in place of natural gas and/or if the hydrogen content of the fluid would exceed a limit of 10-20%.

Transmission pipes in the existing natural gas grids operate under high pressures, from 40 bar up to 100 bar. The steels (low carbon steels) used for building the transmission grids increased in strength over time; the steel X42 is one of the oldest, used in the 1960s, and today operators have started to use the X80 (Figure 9).

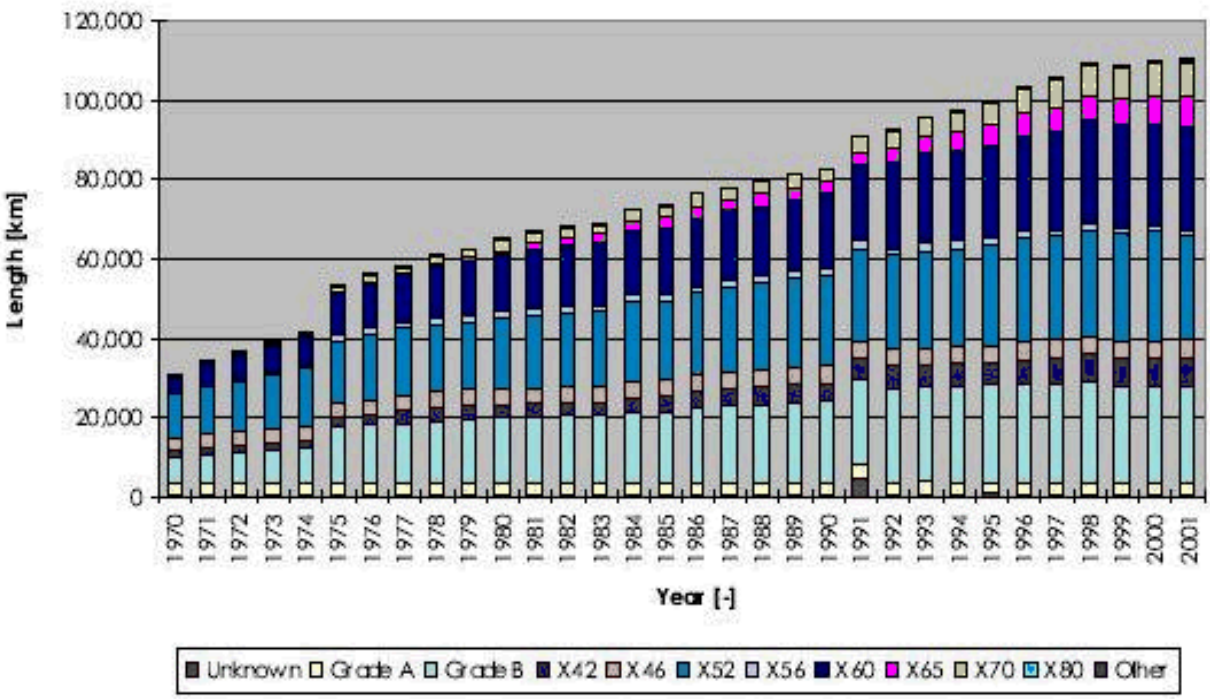


Figure 9: Annual length per grade of natural gas pipeline material[4].

4 5th Report of the European Pipeline Incidents Data Group, ECIG 02.R.0058 (2002)

As mentioned above, the hydrogen embrittlement is a concern for steel pipelines. This is especially true in the context of mixing hydrogen in the NG network, since a general trend is that the higher the mechanical resistance of the steel, the higher its susceptibility to hydrogen embrittlement. This implies that although the interaction of hydrogen with steels has been largely studied in the past, the compatibility of high strength steels such as X80 with hydrogen requires further studies to gain a deep understanding of the effect of hydrogen on this kind of steel.

One could be surprised to learn that hydrogen was transported through pipelines in Europe for many years as city gas (51% H_2) before being replaced with natural gas. However the tendency to embrittlement increases with increasing hydrogen pressure (at least up to 100-200 bar) and purity. The fact that certain impurities, such as oxygen, CO, CS and SO could inhibit hydrogen cracking, together with the low pressures in former city gas lines (5-15 bar) and the lower grades of steels used at that time, explain why the former conditions of city gas transport were less stringent than the possible future transport of hydrogen in the NG pipelines.

For the use of PE materials in the distribution network the concern will be the permeability of the hydrogen through the material, following the issues described in chapter 2.

The project NATURALHY aims at defining the conditions under which the existing natural gas system can be used for the delivery of hydrogen. Preliminary results show from a comparison between fractured surfaces of a X52 steel pipe exposed to hydrogen containing environments and those tested in air, where it can be seen how the hydrogen caused the formation of isolated and small brittle areas and secondary cracks. These areas are not sufficient for decreasing the mechanical properties of the material, but are sufficient for the formation of secondary cracks on the specimen surface. For X70 steel pipes, preliminary results are in line with those revealed for the X52 grade. No differences in terms of elongation were found between reference tests and the one carried out on H_2/CH_4 mixture [NaturalHy 2005].

Other preliminary experiments showed that pressurized gaseous hydrogen can affect the fatigue resistance of the material: it can reduce the threshold value for fatigue cracking and it can also result in an acceleration of the crack growth rate (Figure 10).

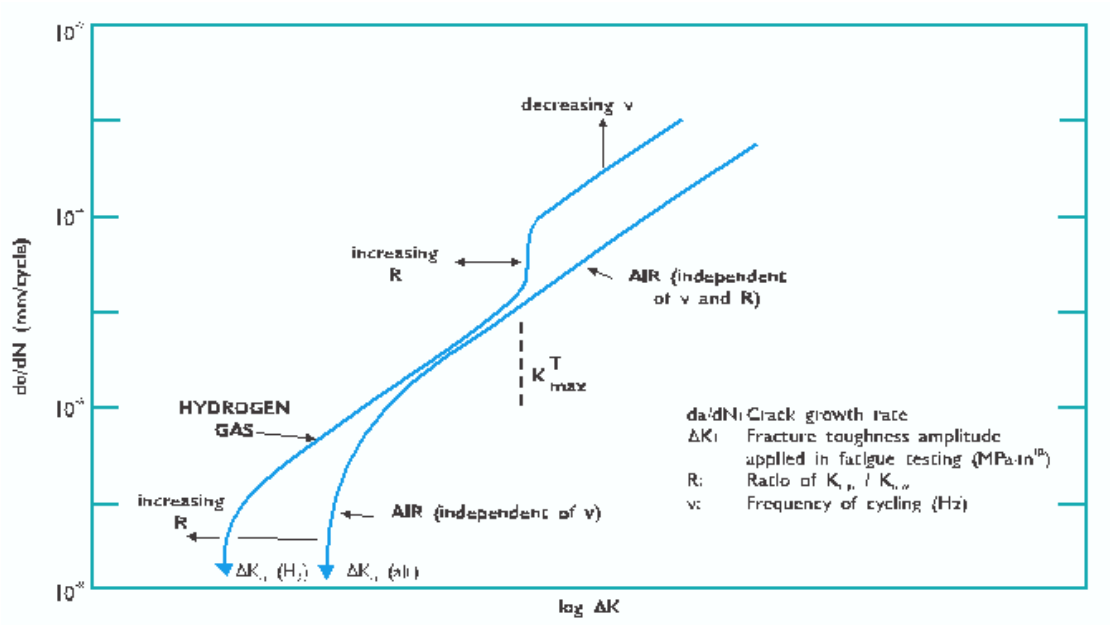


Figure 10: Schematic diagram showing stages of hydrogen-assisted growth for low strength steels 44.

This diagram does not take into account the effect of the hydrogen gas pressure. [Ritchie, R.O; NaturalHy 2005]

3.2.3 Future trends

A complete changeover to pure hydrogen distribution is not likely to occur since some consumers would still require natural gas during any changeover period.

Considering the current most common grades of NG pipelines steels (API5L B, X52 and X60), injection of mixtures up to 20-25% hydrogen seems to be practicable but higher proportions could raise serious problems. It is also possible, with certain modifications, to use pure hydrogen in certain existing natural gas lines. While this optimistic statement appears very encouraging, a realistic approach based on the precautionary principle could be that of tackling the issue, at least at the early stage, on a case-by-case basis, by carrying out dedicated risk assessments for each line before injecting significant quantities of hydrogen into it. The development of in-line coating and lining materials improving the operating integrity of existing pipelines may also be a viable option, but needs experimental development work.

Table 5 summarizes the current vision for introducing hydrogen into the existing natural gas network.

Table 5- Steps for the introduction of hydrogen in the existing natural gas network [Polman, de Laat et al. 2003; datas from HyFrance group]

Time horizon	Maximum H_2 content	Need for adaptations	Main changes required	
			Grid level	End use level
2008	3%	Limited	Adjustment of gas metering and quality control systems	
2020	12%	Significant	Adaptation of high and medium pressure grid: compression horsepower, operating pressures (see text)	Adaptation of Gas engines Development of "broad band" boilers and first replacement phase. Setup of standards and norms
2025	25%	Major	Adjustment of pressure control systems	Second boiler replacement phase

The roadmap proposed by IEA is to introduce a 3% maximum content of hydrogen in the existing natural gas network in the short term (2008). This amount of hydrogen does not need important materials modifications. The most significant investments would be required to pass from 3-12% hydrogen content. A major impact is expected at the end-user level: a number of upgrades of presently existing burning devices (boilers, gas engines, gas turbines) would be necessary to accommodate the change in gas composition and the expected fluctuations of the hydrogen / natural gas ratio.

3.3 End-use of hydrogen, when transported with natural gas

3.3.1 Use of natural gas and hydrogen mixtures in vehicles (Hythane)

Hythane® is a mixture of natural gas and hydrogen, containing usually 20% (by volume) of hydrogen (5–7% by energy within the natural gas composition). Hydrogen and methane are complimentary vehicle fuels in many ways: methane has a relatively narrow flammability range that limits the fuel efficiency and oxides of nitrogen (NOx) emissions improvements that are possible at lean air/fuel ratios. The addition of a small amount of hydrogen do not modify significantly the lean flammability range. The methane has a slow flame speed, especially in lean air/fuel mixtures, while hydrogen has a flame speed about eight times faster. The methane is a fairly stable molecule that can be difficult to ignite, but hydrogen has an ignition energy requirement about 25 times lower than methane.

Hydrogen is a powerful combustion stimulant for accelerating the methane combustion within an engine. The effects on the calorific value of the gas is inversely proportional to the percentage of hydrogen and the reduction of CO_2 emissions is clearly significant for high proportion of hydrogen (>30%) (Figure 11).

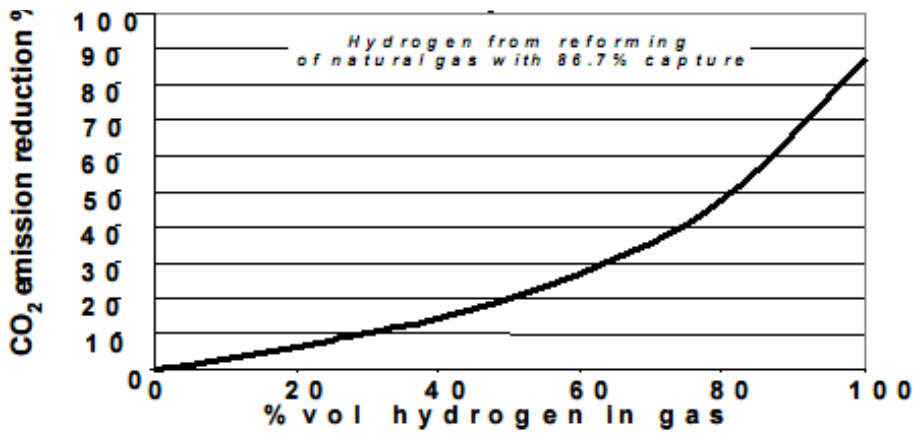


Figure 11: Reduction in CO2 emissions versus hydrogen content of natural gas [IEA-GHG 2002].

One of the main benefits sought by including hydrogen in the alternative fuels mix is GHG emission mitigation. The effectiveness of hydrogen use in a mixed fuel can be measured by the so-called leverage ratio, comparing a non-hydrogen fuel and a mixed fuel. It is defined as the ratio of the proportion of emissions reduction between both cases on the proportion of energy supplied by hydrogen:

$$\text{Leverage Ratio} = \frac{\%\ \text{Emissions Reduction}}{\%\ \text{Fuel Energy Supplied as Hydrogen}}$$

One of the strengths of Hythane in a transition phase is that it does not require such a large infrastructure change as hydrogen. This is especially true in countries where CNG vehicles have a significant market penetration.

3.3.2 Use of natural gas and hydrogen mixtures in domestic appliances

The potential of hydrogen and natural gas mixtures for residential appliances like domestic boilers is currently being studied (particularly with high hydrogen content >50% in the natural gas) and first results (NaturalHy project[5], November 2007) have shown no majors barriers for using these fuel mixtures in standard appliances. Most of the current on-site domestic boilers in Europe have been prepared for gas interchangeability with the G222 reference gas that contains 23 % of hydrogen and 77% of methane (to test the flame flash-back). The EN437 standard (2003/C 313/02[6], boilers commercialised after 1990) is used to verify the flexibility and the performances of the boilers with some non-typical gases in regard to the required gas specifications of the networks in Europe (Wobbe index, density…). This existing ability for modern boilers to tolerate small quantities of hydrogen is a first opportunity to deploy gas mixtures before developing a wholly new generation of domestic appliances designed to accept a large hydrogen content.

Adapting to technologies that use natural gas- hydrogen mixtures could represent an interesting transition option for industries currently using natural gas as a fuel (e.g. glass industry) but wish to reduce their CO_2 emissions.

3.3.3 End-use of pure hydrogen

The distribution of hydrogen in natural gas networks provides a real opportunity for end-users to obtain pure, or nearly pure, hydrogen for a variety of applications, thus helping to create “local hydrogen centers” and enabling the transition towards a hydrogen energy deployment. However, to achieve this, low-cost and efficient means of separating hydrogen from the gas grid must be available.

3.3.3.1 Separation methods

There are two main solutions for hydrogen separation. Some basic features for each one are given below.

The first one is Pressure Swing Adsorption (PSA), widely used in the process and refinery industries. This is currently the method used to purify and separate hydrogen after its production by Steam Methane Reforming. It is possible to use the Pressure Swing Adsorption technique to get very pure hydrogen (above 99,9%), but the technology is better adapted for feed-gas containing at least 20-25% hydrogen, and more generally above 50%.

The second one is membrane separation. These membranes can be made of a variety of materials (microporous or dense ceramics, porous carbon, polymers, or dense metallic materials). However only two classes are commercially available at a significant scale:

[5] http://www.naturalhy.net/docs/Newsletters/NewsLetter_06_HIGH.pdf
[6] Commission communication in the framework of the implementation of Council Directive 90/396/EEC of 29 June 1990 on the approximation of the laws of the Member States relating to appliances burning gaseous fuels (2003/C 313/02)

- Polymeric membranes, which are polymeric hollow fibers, usually made from polyaramide and polyamide. Gases with a high permeation rate, such as hydrogen, diffuse through the hydrogen membrane into the hollow interior and are channelled into the permeate stream. Gases flow around the fibres and into the residue stream. They work below 100°C. They can offer a lower investment costs and packaging advantages when compared to PSA technologies, but the purity of hydrogen that can be reached is limited to not more than 99% in a single stage.

- Dense metallic membranes, based on Palladium and its alloys. Hydrogen is dissociated and the mechanism of transport is an interstitial diffusion of atomic hydrogen. They work between 300-600°C. Metallic membranes allow a higher purity of hydrogen to be obtained than polymeric membranes, but suffer from a lower recovery rate, and a high costs.

The search for membranes that offer at the same time low costs, high purity and high recovery levels is one of the key issues in R&D efforts linked to the development of a hydrogen deployment. Durability and poisoning issues have also to be considered.

Today, for the specific application of separating hydrogen from natural gas, with a content of about 10% in hydrogen, an efficient solution to achieve both a high purification and high recovery is to combine the existing technologies, in particular PSA and polymeric membranes.

3.3.3.2 Techno-economic assessment of the separation step

The techno-economic assessment of the separation costs addresses two types of issues:

- The comparison of the costs of transport of pure hydrogen vs. NG/hydrogen mixtures

- The location of the separation of hydrogen from NG.

This separation can be performed at different points in the chain: at the far end of the distribution network, just before its use, or in “semi-centralized” points, for example at the city gate.

Once again, this type of question cannot be addressed without a complete optimisation study, beyond the scope of this report. For the sake of illustration, some results, extracted from a case-study performed by the HyFrance group (a French experts group on Hydrogen and FC issues) in the framework of the HyWays and NaturalHy projects is given below [NaturalHy, 2007].

The case study considers the use of pure hydrogen for cars, for a single city (the Sénart City). The hydrogen is transported with NG (10% vol H_2). The hypothetical composition of the feed-gas is given below:

H2	10.0%
N2	2.9%
CH4	79.4%
C2+	6.5%
CO2	1.3%
TOTAL	100.0%

The output hydrogen is pure at 99.99% (90 ppm CH_4 and 10 ppm nitrogen impurities in hydrogen), which is compatible with its use in a Fuel Cell (99.99% with a CO content of less than 0.2 ppm).

The hydrogen demand comes from the HyWays "high" penetration scenario for 2020 and 2030, applied to the city of Sénart, which represents 311 and 2750 Nm^3/h respectively of hydrogen, and 4 and 15 fuelling stations.

Three configurations were considered. Note that the costs estimations were made in the framework of a complete energy chain, where the hydrogen is produced by SMR and where the CO_2 is captured. However, these steps are the same in the three chains considered and what matters here are the differences in the separation step.

- Transport of pure hydrogen (Figure 12)
- The mixture is separated centrally on the outskirts of the metropolitan area, then hydrogen is transported via pipelines dedicated to the different hydrogen service stations (Figure 13);
- The mixture is sent to fuelling stations where it is separated locally in facilities of lower capacity (Figure 14).

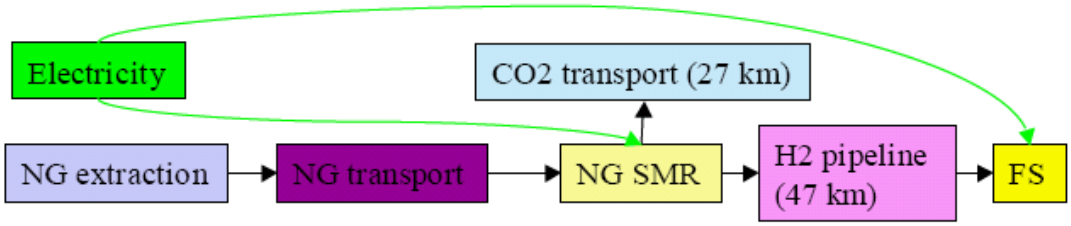


Figure 12: Chain with the transport of pure hydrogen (Case 1) (Figure form HyFrance group).

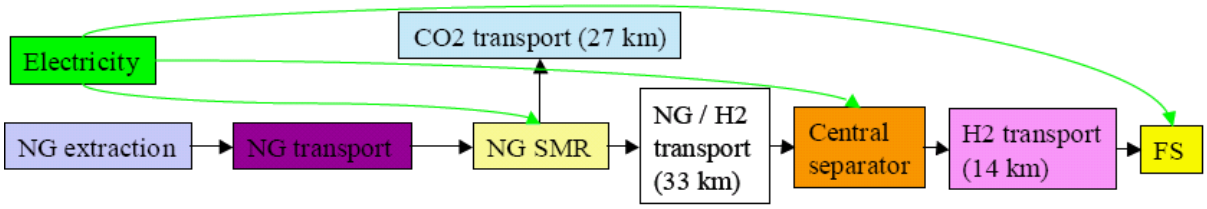


Figure 13: Chain with the transport of NG/H2, and central separation (Case 2) (Figure form HyFrance group).

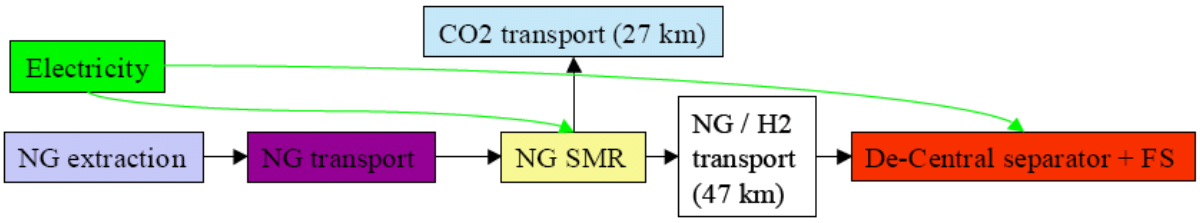


Figure 14: Chain with the transport of NG/H2, and separation at the fuelling station site (Case 3) (Figure form HyFrance group).

The calculated costs of hydrogen delivered in fuelling stations in the different cases studied are shown in Figure 15. These estimations reflect a very specific case study, with the performance of current separators. Despite the partial character of the conclusion, the following trends can be outlined:

- For a small hydrogen demand (2020), the transport of hydrogen mixed with NG is a competitive solution when compared to pure hydrogen pipelines, or cryogenic trucks (see case 2, 2020)
- The costs of the chain with centralized separation is lower than that of the chain with decentralized separation (at the fuelling station site), in both "scenarios" (2020 and 2030) studied

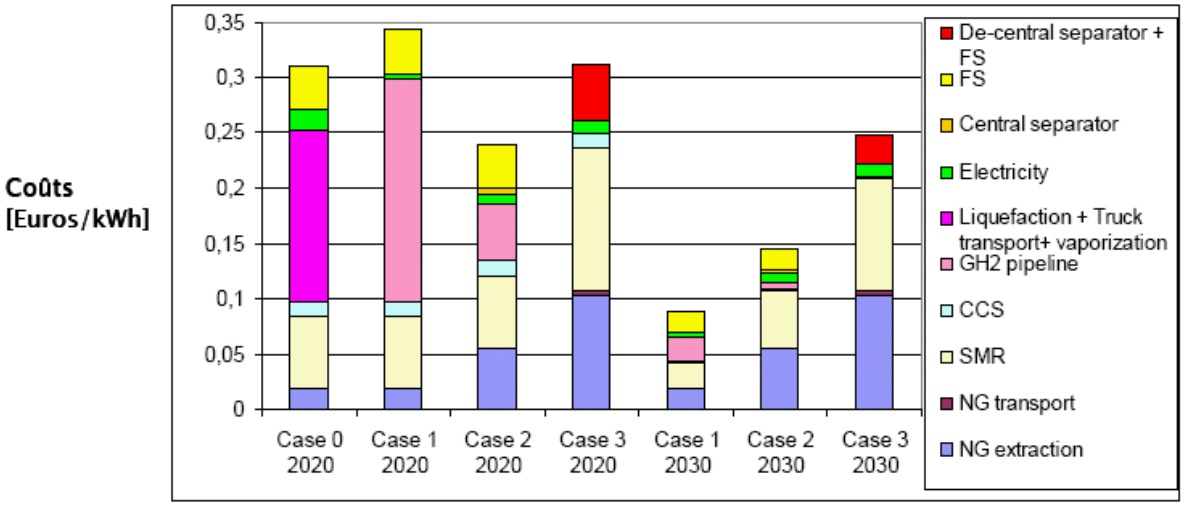


Figure 15: Costs of hydrogen delivered in stations for the three cases presented in figures 11,12,13. (Figure from HyFrance group).

No credit for the off-gas was included here. For the sake of comparison, the case 0 refers to the transport of hydrogen in cryogenic trucks (only for the 2020 case, where hydrogen demand is still low) [HyFrance report 2007].

Although this study deals with a very specific case, it emphasizes the fact that the transport of hydrogen in the natural gas pipeline can be financially attractive in the transitional period, despite the limited performance of the separators to date. Thus, the separation costs decrease with higher pressure grid (separation operated directly on the transport grid at 80 bar).

4. Conclusions

A number of different solutions for hydrogen distribution have been presented here, with insights on the costs and strengths and weaknesses of the various technologies reviewed. It is important to note that all costs data disclosed pertain to static evaluations, which means that the costs of a technology, or of chains of technologies, is evaluated in different conditions, at a given time. It is particularly important to note this point at a time of rapidly changing oil and steel prices. When planning the deployment of a hydrogen infrastructure, dynamic models, exhibiting an evolution in time according to the market demand, allow to account for the necessary existence of transition periods before the possible existence of a dedicated hydrogen infrastructure, according to the considered scenarios. The final decision of a transportation solution of hydrogen will also be directly influenced by the environmental performance of the different pathways.

In the near term, accepted guidelines still apply: Distribution of Hydrogen as a compressed gas remains favoured up to 200-300km while demands are low; higher distances or demands favour liquefaction, with its more Hydrogen-dense transportation justifying the extra fiscal and energy cost of liquefying the Hydrogen..Further increases in sustained demand could lead to commitment to invest in pipeline infrastructure, particularly to major centres of usage. However, it is clear that technologies that reduce the investment cost of pipeline infrastructure will facilitate such a build-up, so the development of robust new technologies such as plastic pipelines remains an important long-term objective. In the medium term, use of the Natural Gas pipeline network and Hydrogen separators appears to be potentially attractive in some situations, despite the immaturity of the separator technology.

It is important to note that socio-economic factors will also be important in the future distribution of hydrogen. Detailed build-up scenarios for a future hydrogen infrastructure were investigated in the project HyWays. Here it was also shown that not only stringent economical ("least-cost") considerations can be made, but supply routes will also need to take into account the market demand for the form of hydrogen, as this is the case in the transport sector. When, for instance, LH2 is required for refuelling, part of the hydrogen at a fuelling station needs to be supplied as LH2 as liquefaction cannot carried out locally. This will change cost-estimations for supply routes, as will business decisions by intermediate sellers, i.e. fuelling stations, to maybe choose a supply route for a higher hydrogen demand than there actual one to cover increases in demand. Certainly all this will be subject to availability of the required supply technology. Work in other workpackages of the project Roads2HyCom illustrates, for instance, possible short term limitations in capacity for LH2.

Another alternative for hydrogen transport in pipelines or in trucks, which has not been discussed, may also arise in the future: transport of hydrogen stored in solid form. Indeed, strong R&D efforts are made on solid (or liquid) materials to store hydrogen with a high gravimetric and volumetric density. These materials range from adsorbants to complex / metallic hydrides, or compounds evolving hydrogen when hydrolysed (chemical hydrides, ammoniaborane, etc.). Any progress in this field will have positive impacts on the performance of hydrogen transport for mobile hydrogen

end-user applications. It could provide an interesting contribution to transport by gas trailers or cryogenic trucks in a transition phase. However, because of the huge quantity of rare metallic materials required, this solution become limited for a higher hydrogen demand.

At last, beyond the techno-economical issues discussed here, the successful deployment of a hydrogen infrastructure will require a strong co-operation between the various stakeholders of the hydrogen energy chain, namely the hydrogen producers, the pipeline manufacturers and/or operators, and the end-users, together with efficient support from governmental policies.

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