Title
Tech Brief: Pipelines for a Hydrogen System in California

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Publication Date
2023-03-01

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March 23, 2023

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Reference No. UCD-ITS-RR-23-15

Acknowledgments

We gratefully acknowledge funding and guidance from the following organizations in support of this study:

Air Products	Aramco
California Energy Commission	Chevron
General Motors	Honda
Hyundai	International Energy Agency
Leighty Foundation	NICE (Clean Energy Institute)
National Renewable Energy Laboratory	Shell
SoCalGas	South Coast Air Quality Management District
Toyota	

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Executive Summary

This paper summarizes a range of information regarding pipelines in the context of building out a hydrogen system in general, and specifically for California. We draw on different studies, especially those providing techno-economic data that can assist in comparing technologies and options on both a technical and cost basis. We draw on experiences in Europe, where hydrogen pipeline concepts are actively being developed and even implemented. This information includes technical requirements, capital costs, fixed and variable O&M costs associated with installing new hydrogen pipelines, and repurposing existing natural gas pipelines for blending or dedicated hydrogen carrying purposes. We also look at situational factors such as where pipelines may be built, comparisons to use of trucks to move hydrogen and transmission lines to move electricity, and other factors.

Overall we find that for a large hydrogen distribution system, construction of new pipelines may offer the best combination of reliability and cost; conversion of existing natural gas pipelines may be cheaper but poses certain issues such as compatibility of hydrogen with the pipeline and available locations of pipeline. Blending hydrogen into an existing natural gas pipeline may be cheapest overall (at least in the short term) but poses issues and costs of recovering the hydrogen. It also may create impacts on the other end use services offered by the pipeline.

We find that for long distance energy transport, newly built pipelines can be competitive with newly built or expanded electricity transmission lines, with the position of pipelines improving with both distance and needed capacity. Reassigned (retrofitted) existing pipelines have among the lowest costs, though with the caveats mentioned. New pipelines also may have a much smaller corridor “footprint” than electric transmission lines, which may be important in new corridors.

Figure ES-1 provides examples of the cost of moving energy via hydrogen in pipelines versus electricity in high-tension lines. In a case with smaller capacities (equivalent to 1 GW) and shorter distance moved (300 km), a new build hydrogen pipeline is competitive with electricity transmission (or slightly cheaper), while a repurposed pipeline can be considerably cheaper. For larger volumes and longer distances (e.g. 5 GW, 1000 km), hydrogen pipelines considerably outperform electricity, being about half the cost for DC lines and a quarter the cost of AC lines.

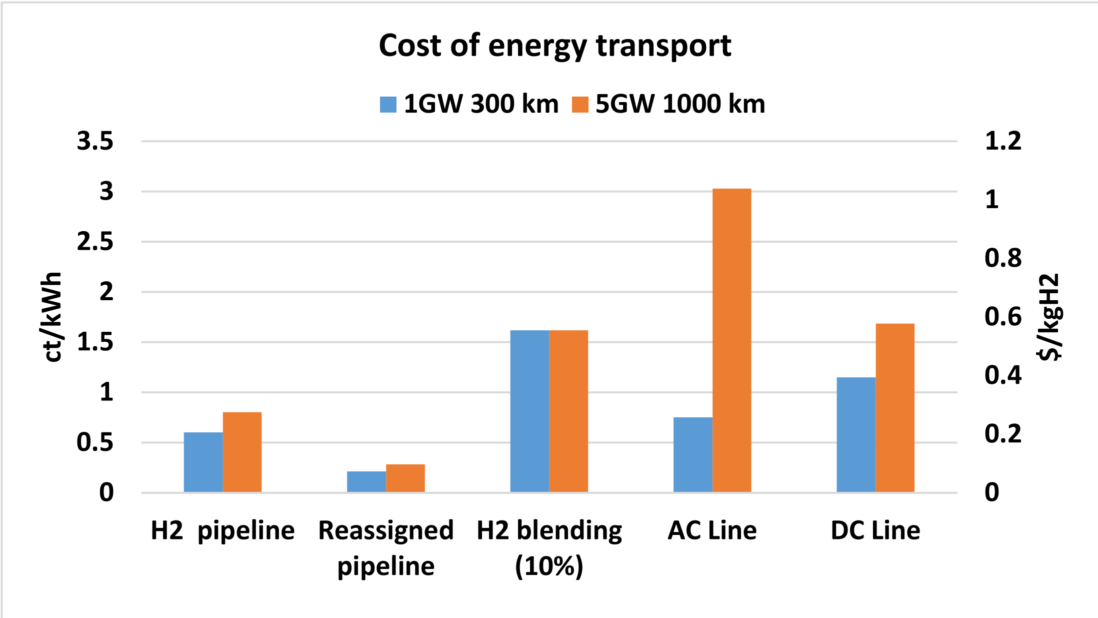

Figure ES-1. Comparison of energy transport options for 1 GW capacity over 300 km[1]

Further research is needed to fully explore the viability and cost of various pipeline concepts such as retrofits, and the overall end use effects of blending different levels of hydrogen into pipelines, as both options utilize the existing infrastructure to lower the cost but also are constrained by the same underlying infrastructure. Consequently, our results show that newly constructed pipelines can provide the flexibility and an optimal distribution of the pure gas at a very low cost, if the pipeline size is sufficiently large and the pipeline is used fairly intensively. Construction takes time from permitting to operation and may have obstacles such as rights-of way, permitting, and various "nimby" problems, though arguably still easier and potentially cheaper than construction of new transmission line systems, which require substantially larger buffer corridors thus exacerbating the associated "nimby" issues.

This assessment considers a simplified/generalized comparison based on the unit cost to convey a given amount of energy to end users. Other factors, such as storage and balancing functionality, community acceptance, acquisition of rights of way, production opportunities, end-use applications/needs, etc. can all make a significant difference in the cost and viability of these options.

[1] Conversion factors: 100 MW of H2 = 61 tons H2/day; H2 capital cost $1000/kW = $1650/(kg H2/d). 1 kWh = 0.025 kg H2=> $0.01/kWh = $0.40/kg[1] Conversion is done on an equivalent energy basis, using higher heat value for hydrogen (1 kg H2 has an energy content of 142 MJ)

Introduction

Pipelines are generally regarded as an optimal long-term, long-distance, high-volume transmission system for gaseous fuels since their operating costs are very low. They make sense for large systems such as the current natural gas system in California. They are expensive to build and only cost effective when moving fairly large amounts of gaseous fuel (i.e. high capacity factors), hence pipelines require a substantial demand concentration. Thus they are not typically built for small markets or systems. Smaller pipelines such as natural gas distribution in cities also exist; these generally use lower cost, lower grade materials given lower pressure requirements. Currently, only a very limited number of initiatives actively investigate hydrogen pipeline networks in the cities [2]. This is also supported by the research indicating a switch from natural gas boilers to heat pumps in buildings providing 60-80% of residential heat in order to achieve net zero emissions by 2050 [3].

At least as a transportation fuel, today's hydrogen is moved mostly by trucks, except for a few cases where there is piped hydrogen available near stations or produced on-site. In contrast, much of hydrogen for industry is moved in pipeline systems, usually in small areas, such as within and near oil refineries. The lack of larger pipeline systems is due mostly to sparse demand for hydrogen in any one area, and the tendency to produce hydrogen close to (or on site) of its intended use. Eventually though it may be more cost-effective to produce hydrogen far from end uses, and with sufficient volume, large scale pipeline systems will become an important low-cost transmission/distribution option.

This paper explores hydrogen pipelines in the context of growing hydrogen systems for transportation and possible connected stationary demands, considering demand, supply and transmission needs and costs. The paper considers three types of pipeline development approaches:

- H2 blending into an existing (probably natural gas) pipeline
- Retrofitting of an existing pipeline to become a dedicated hydrogen pipeline
- Construction and installation of a new dedicated hydrogen pipeline

Each of these options has certain advantages and disadvantages. We focus primarily on dedicated pipelines but also cover some concepts, technologies and costs related to retrofitting and blending. We also compare pipelines to other transmission options such as trucks, and to moving electricity via transmission lines as an alternative to moving hydrogen (and then producing hydrogen close to end-use locations).

Developing dedicated pipelines

Currently, there are already several isolated hydrogen pipeline networks supplying industrial sites in the US, with a total length of 1600 miles [4], for which construction is undertaken in observation of international hydrogen piping norms. However they are limited to a few locations such as the Gulf Coast area where hydrogen pipelines serve refineries and chemical plants. In many places, hydrogen pipeline systems would need to be started "from scratch". This includes California where there are currently only about 27 miles of hydrogen pipeline.

For reference the current industrial hydrogen use in California is about 1.6 million tons per year, and additional hydrogen supply is under development. Future demand from 1-10 million road vehicles might be 1000 to 10.000 tons per day or 0.4-3.7 million tons H2/year. A hydrogen pipeline transmitting 1-5 GW of energy or about 0.7-3.5 million tons H2/year could meet the demand of a major hydrogen hub, even with future expansion of hydrogen use.

Almost all hydrogen produced in California today is via large scale natural gas steam methane reforming (NG SMR) or refinery byproducts. Table 1 lists 2022 data for California merchant and on-purpose captive refinery hydrogen. A little more than half of California's hydrogen (0.85 million tonnes per year) is produced "on-purpose" at refineries and is considered "captive" – or not available for other uses. The remaining hydrogen is supplied by merchant hydrogen producers (0.76 million t/y) and could potentially be available to supply emerging demand centers. At present biomethane is being used to decarbonize SMR-based hydrogen. In future some fraction of California's 1.6 million t/y of SMR based hydrogen might be decarbonized by adding CCS or replacement by green H2 production via electrolysis. Further development of these technologies could help serve future hydrogen energy markets such as heavy-duty transportation and energy storage.

Table 1. Hydrogen Production in California (HyARC 2022) [5]–[7]

MERCHANT HYDROGEN PRODUCTION IN CALIFORNIA					
PRODUCER	**CITY**	**H2 Source/ Process**	**Product**	**Capacity t/d**	**Million t/y**
LIQUID MERCHANT HYDROGEN					
Air Products	Sacramento	SMR	H2	6	0.002
Praxair	Ontario	SMR	H2	20	0.007
GASEOUS MERCHANT HYDROGEN					
Air Liquide	El Segundo	SMR	H2	207	0.076
Air Liquide	Rodeo	SMR	H2	289	0.105
Air Products	Carson	SMR	H2	241	0.088
Air Products	Martinez	SMR	H2	212	0.077
Air Products	Martinez	SMR	H2	84	0.031
Air Products	Sacramento	SMR	H2	n/a	n/a
Air Products	Wilmington	RFG SMR	H2	386	0.141
Praxair	Ontario	SMR	H2	29	0.011
Praxair	Richmond	SMR	H2	627	0.229
TOTAL MERCHANT H2 PRODUCTION				**2100**	**0.767**
HYDROGEN PRODUCTION AT CALIFORNIA REFINERIES (2022)					
PRODUCER	**CITY**	**t/d**	**Million t/yr**		
Chevron USA Inc	Richmond	793	0.29		
Chevron USA Inc	El Segundo	178	0.06		
Phillips 66 Company	Rodeo	53	0.02		
Phillips 66 Company	Wilmington	252	0.09		
San Joaquin Refining Co Inc	Bakersfield	10	0.00		
Martinez Refining Co LLC	Martinez	430	0.16		
Tesoro Refining & Marketing Co	Carson	288	0.11		
Valero Refining Co California	Benicia	325	0.12		
TOTAL		**2329**	**0.85**		

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San Joaquin Refining Co Inc	Bakersfield	10	0,00
Air Products	Torrance	345	0,13
Air Products	Martinez	430	0,16
Tesoro Refining & Marketing Co	Carson	288	0,11
Valero Refining Co California	Benicia	325	0,12
TOTAL		**2674**	**1**

Building a pipeline requires large investments and confidence that there will be a market for the gas it is meant to carry by the time it is ready. One approach to this problem is to "stage" a pipeline, adding pieces to match a growing hydrogen system. But if a large, long line is needed in advance of an expected developing market, risks will be inherent. On the other hand, building a pipeline early on can help spur a market and provide a "backbone" to enable system growth. There are two main competing strategies: one is to develop the hydrogen pipeline and other infrastructure based on confirmed initial demand, most likely at large industrial facilities or clusters. The other is to make the large initial investment with the further plan to develop demand and supply nodes around it. This may be a better strategy for ultimate system growth and sizing but will tend to be riskier and may require more policy support.

In California, given that the supply of hydrogen will likely need to be renewable sooner rather than later, and as the locations for renewable hydrogen production in large volume and at least cost may be limited (or outside of the state), the distances between various industrial areas and renewable energy production sites to supply hydrogen could be quite large. This would justify development of a backbone network of hydrogen pipelines to connect these and initiate a system with significant production/transmission volumes. A prominent example of such strategy is the proposed pan-European hydrogen backbone strategy [8]. Recently Southern California Gas and partners have embarked the Angeles Link pipeline project to bring green hydrogen to key hard-to-electrify markets in Southern California, such as industry, heavy-duty transportation, and electric generation." [9].

On the opposite side of the spectrum lies a strategy that focuses on hydrogen demand in the transport sector, which is generally more distributed among different refueling stations and will likely happen incrementally and possibly slowly. This will result in lower volumes to each end user and possibly sparse numbers of users for at least an early phase of development. However it also could mean shorter distances from production to at least some stations. Small scale and distributed users tend to push toward a hydrogen delivery system via trailers or liquid hydrogen trucks [10].

In between these two extremes lie many variations and combinations, such as integration of nearby industrial or port facilities as well as local renewable sources (even if somewhat high cost) to reduce delivery distances; systems with mixed industrial and smaller demand centers may use a combination of pipelines and truck delivery, using the later for the last mile delivery while supplying the regional hubs with the pipelines. The hydrogen hubs concept is particularly useful to justify building large scale production and delivery systems (to hub storage), with final short-distance distribution to end users via trucks.

We consider some of these issues in this tech brief, but much of the analysis of this type of question and how specific systems may be built out occurs in our separate modeling efforts that will draw on this paper. Here the focus is more on the specific attributes and costs of pipelines.

Uses and specifications of pipelines

As mentioned, the three key land-based routes of hydrogen distribution are gaseous hydrogen trailers and pipelines, as well as liquid hydrogen trucks. The choice of the most cost-effective delivery method depends on volume and distance, but also on the chosen means of storage and form of delivery to end user, since changes in the state of hydrogen increase energy losses and costs. Gaseous hydrogen trailers could offer a cost-effective solution during the introduction phase, which will be marked by low and sparsely distributed demand. However, they become less economical in later market stages when hydrogen demand increases, or if the end use stores hydrogen as a cryogenic liquid.

With sufficient hydrogen demand, a last mile distribution system using a hydrogen pipeline to end user (such as a hub to a refueling station) can sometimes be a viable option, since the alternatives are not without their challenges. Transport of hydrogen by tube trailer can be relatively low cost but trailers have limited capacity and running multiple trailers per day to a destination is cumbersome. Liquid hydrogen (LH_2) has challenges similar to those of liquefied natural gas (LNG), which requires cryogenic cooling equipment, high insulation and systems to avoid boil-off losses. Hydrogen pipelines can minimize the costs of hydrogen handling and storage at end use sites, compared to on-site pressurized storage, for example. They can also help reduce the impact of hydrogen delivery on the already intensive road-based traffic [11].

For smaller markets or to reduce early investment costs, the use of smaller diameter pipelines may be advantageous if other direct and indirect cost factors such as engineering, right of way, installation etc. are managed; these smaller pipelines could also reach viable utilization rates faster than large diameter pipelines. However, in the long term this approach could result in higher per-unit hydrogen costs, due to lower throughput potential and resulting higher per unit capital cost, as well as greater pressure losses compared to larger diameter pipelines. (A strategic deployment of large diameter pipeline would incur large initial investment costs with low utilization in the beginning, but in the long term would provide a preferable state of the system with the lowest delivery cost.) One possible way to approach this problem is to assess the anticipated size of the throughput, which can indicate the maximum size of the required pipeline. Then the anticipated rate of the adoption as well as supply and demand volatility need to be scrutinized, especially in the light of long planning and building timeframes of such infrastructure and potential feedback effects, where availability of the infrastructure can accelerate the hydrogen adoption and thus improve the initially assumed utilization of the infrastructure. Timing questions could also benefit from the likely permitting and construction time of a pipeline, which could be several years in any case, buying time to develop “off-take” end uses.

Typical pipeline system configurations

Depending on the maturity and the scale of the market there are two ways to feed hydrogen through a pipeline system and reach a viable state (such as pressure level) for the end user. First, the pipe can be used to supply the consumer directly, at the needed pressure. Second, the pressure level in the network can be lowered by intermediate pressure relief in order to adjust the pressure differential to final customer needs. The first case is common in today's hydrogen pipelines, as the example of the pipeline system in Germany indicates. Piston compressors are then used before the gas is injected. No further compression takes place in the pipeline network. This type of operation is very simple in principle and requires few components, but it presents the operator with the challenge of always keeping the pressure within certain limits. The consumers always want a certain pressure level and tolerate only small fluctuations of a few bar. The system is thus inherently sluggish because feed-in and feed-out changes can only be realized slowly. The second case is common in the natural gas network, where there is a transition from the large lines of the transmission network to the distribution network via throttling stations. In the transmission network, which serves long-distance transport, the natural gas system has a higher pressure.

Options for system design

In the first option, to feed out of the pipeline, the consumers, i.e. refueling stations, are connected directly to the transmission pipe with spur lines. A clear separation between transmission and distribution is thus eliminated. The idea behind this concept is that a large transmission pipe branches out further and further and the pipe diameter tapers off with decreasing throughput. In this way, each filling station is connected via the pipe directly to the source, in this case the hub. The advantage of this concept is the simplicity since few intermediate components, such as compressors or throttling stations, are required. This results in lower initial overall investment costs. The disadvantage, however, is that the filling stations receive different pressures, and the transmission tube is directly exposed to any fluctuation. Due to the pressure drop along the pipeline, those that are located directly at the pressure regulation point have the additional advantage of always being supplied at a higher-pressure level than those far away. Furthermore, due to the direct connection of the refueling stations to the transmission system, either very high hydrogen quality needs to be facilitated across the overall system or each station requires its own purification equipment as it is today with quality sensitive natural gas consumers. This can be problematic in case of use of inhibitors for pipeline reassignment (see below).

Alternatively, hydrogen refueling stations can be connected via the second approach, an indirect connection. The filling stations are not connected directly to the transmission pipe, but via a node or hub (with truck delivery an option). These are a kind of "secondary source" that does not consume the hydrogen, but only passes it on. A hub is a station that has a connection to the transmission pipe and feeds into the distribution network. In addition, as needed, compressors, turbines, purification equipment, control units, and technical storage units can be installed. In this concept, the transmission network is clearly separated from the distribution network.

In this case, such separation of the systems introduces new components at the hub, thus increasing the overall system complexity and the initial investment cost. However, due to the separation a more homogenous access to the transmission system can be facilitated thus simplifying connection of new refueling stations. Furthermore, more options for delivery, such as use of truck trailers to supply small and far away stations, are opened.

Transmission role

Transmission pipelines are designed to transport large volumes of hydrogen, thus maximizing the pressure and the velocity of the gas, increasing the throughput of the pipeline. With large diameter pipelines (such as 1 meter) and high throughput, pipelines can achieve very low costs per unit hydrogen moved. For a given diameter pipeline, at higher pressures more hydrogen can be transported, but the increased flow rate moves the system into increasingly unfavorable areas in terms of friction, and pressure losses increase.

Distribution role

For distribution lines, a diameter of 100 mm is the minimum size that is feasible. Pipeline diameters below this are only suitable for smaller connections *e.g.* within plants or other facilities. With increasing velocity the mass flow also increases (see Figure 1), but the pressure losses also increase at the same time (see Figure 2) [12]. Thus a velocity of 10 m/s can be used as a conservative estimation. Hence even with the minimum diameter of 100 mm and the minimum pressure of 30 bar at the end of a pipeline, a distribution pipe can transport about 17 tons of hydrogen per day, enough to supply 17 average filling stations.

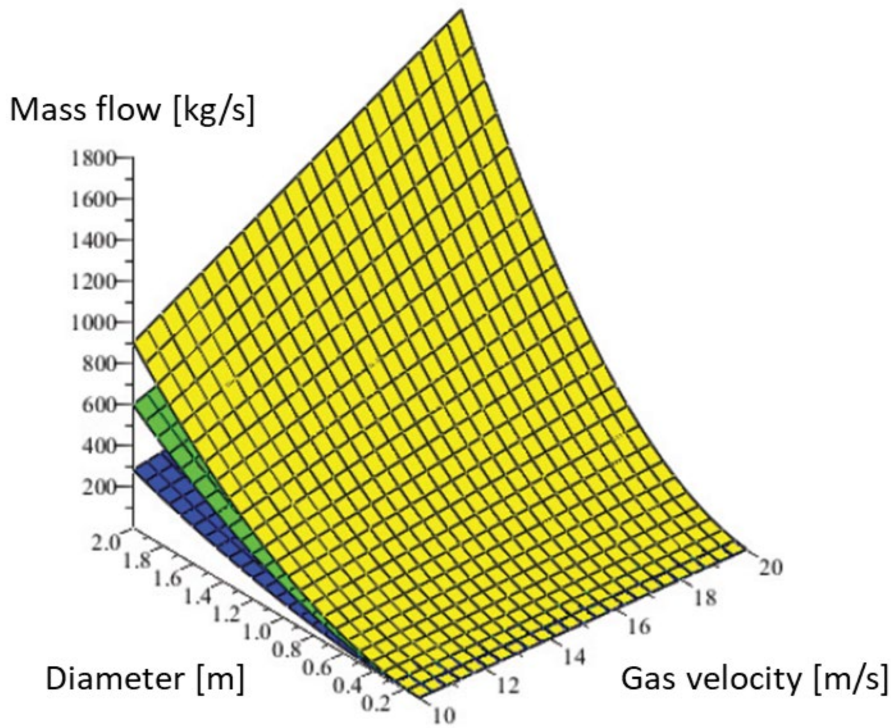

Figure 1. Mass flow in relation to diameter, gas velocity and pressure. Yellow: 100 bar, green: 65 bar, blue: 30 bar [12]

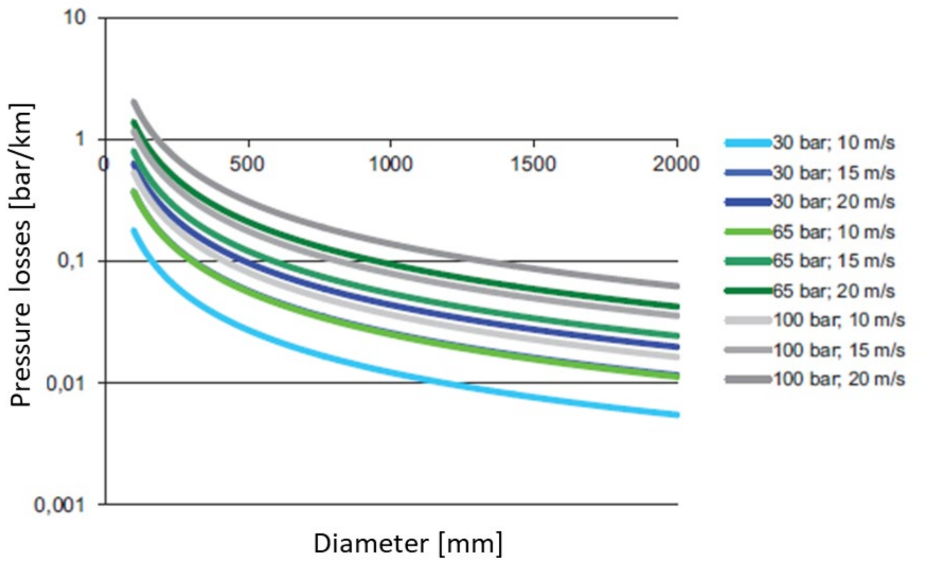

Figure 2. Pressure losses in relation to pipeline diameter, pressure, and gas velocity. Blue: 30 bar, green: 65 bar, gray: 100 bar [12]

Costs of dedicated hydrogen pipelines

As mentioned, pipelines can be a very cost-effective means of transporting high volumes of hydrogen. Construction of new pipelines is undertaken observing international hydrogen piping norms [13], [14]. Costs depend on system sizing as well as the state of market development, and despite the 3000 miles of the global existing hydrogen pipeline [4], this is still a relatively nascent market compared to pipelines for natural gas, which in US alone covers more than 3 million miles [15]. The present and future costs of hydrogen pipelines is an active area of research and analogies to the costs of natural gas pipelines are often made. Drawing on the experience with the construction of natural gas pipelines, Figure 3 displays the typical cost structure of a pipeline and its dependency on diameter. In general the fixed cost components such as labor, right of way and some others trend lower with increasing diameter, while the per unit (and overall fraction of) costs from materials increases. However, while the surface area of the pipeline increases near-linearly, the throughput of pipeline increases quadratically, thus diminishing the impact of the material costs. Consequently, the cost of larger pipelines is dominated by the material costs but are substantially lower per unit of throughput than is the case for smaller pipelines. This is reflected in the somewhat different stories told by Figures 3a and 3b.

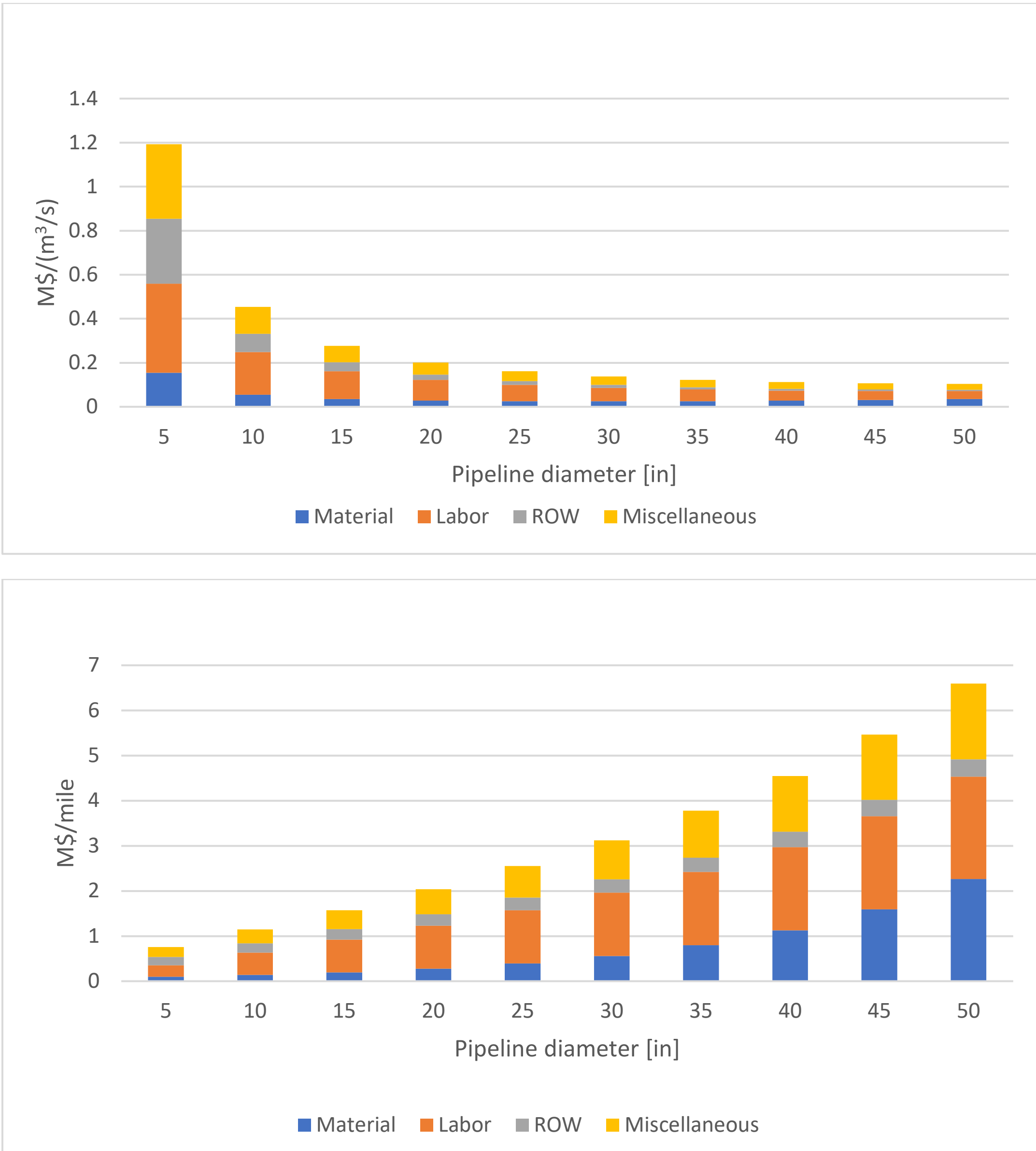

Figure 3. Typical cost breakdown of a natural gas pipeline project per unit diameter (3a) and per unit pipeline length (3b) [16][17]

Estimates of the specific costs of increases in hydrogen pipeline diameter are shown in Figure 4 [18]. The costs rise non-linearly with diameter, making the per-unit investment costs higher for larger than for smaller pipelines (though operating per-unit costs are much lower). The data come from varied sources in the literature, mainly in the European context, and reflect project data with specific bottom-up assessments. Such project data does not always indicate if costs are only for the pipeline material and associated works, or also for related expenses such as securing the rights of way for the land, permitting fees, etc. These costs may be significantly different by location and jurisdiction.

This Figure 4 also includes costs for “reassigned H2 pipelines”. This reflects taking existing natural gas pipelines and retrofitting them (such as relining them, mitigating embrittlement issues and other cost factors) to use hydrogen. Initial investigation of the German natural gas (NG) transmission grid by Cerniauskas et al. has shown that, despite needed measures, pipeline reassignment can reduce yearly pipeline expenditures by up to 80% in comparison to a new, dedicated hydrogen pipeline. Pipeline reassignment is further discussed below.

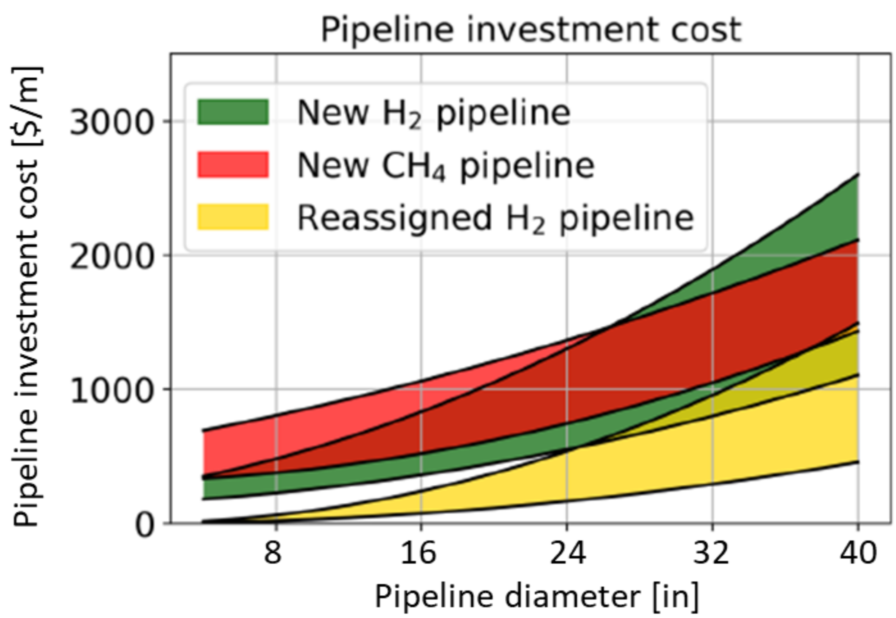

Figure 4. Overview of pipeline investment costs [18]

Key techno-economic parameters of hydrogen pipelines

Hydrogen pipelines can be operated at various pressure levels, depending on consumer requirements, pipeline system design and pipe material properties. Table 2 below, describes the range of various input parameters required to characterize a hydrogen pipeline system. Due to the limited available data, additional parameters from a natural gas system are included. On the one hand, due to the well-known costs and operational properties of a natural gas system, the operation and maintenance (O&M) costs and pipeline depreciation provide the best case for the values. On the other hand, due to associated uncertainty regarding the costs and operation of a hydrogen pipeline system, the parameters could be substantially more conservative.

Table 2. Estimated techno-economic parameters of hydrogen pipelines [10], [12], [19]–[22]

Parameter	Lower range	Upper range
Pmax	70 bar	100 bar
Pmin	30 bar	70 bar
Compressor O&M	1.5%	4%
Gas regulation O&M	1.7%	2%
Pipeline depreciation	40 a	55 a

Retrofitting pipelines for dedicated hydrogen transmission

Conversion of natural gas pipelines for dedicated hydrogen transport can offer an attractive option in some situations, especially when there is available pipeline capacity and separate parallel pipeline strings can be utilized [8]. In general there are four different pathways which can be leveraged to reassign the pipeline, namely operation of pipeline without modifications, re-coating, admixture of additional inhibitors and lastly deploying a dedicated hydrogen pipeline within the natural gas pipeline (pipe-in-pipe). Table 3 below sums up the key strengths and weaknesses of the pipeline reassignment alternatives.

Table 3. Strengths and weaknesses of pipeline reassignment alternatives [19]

Reassignment alternative	Strengths	Weaknesses
Pipelines without modifications	Few modifications are required Limited material fracturing under static load	Increased material degradation
Coating	Specific protection layer against H_2 embrittlement Developed industrial processes on metal surfaces	No known on-site coating procedures Excavation of pipelines probably required
Inhibitors (O_2. CO, SO_2)	Limited modifications are required Protection layer undermining hydrogen permeation	Toxicity and security risks Purity requirements of hydrogen processing and fuel cells
Pipe-in-pipe	Combined benefits from inner and outer pipeline	Required additional material Excavation of pipelines probably required

In the case of pipelines without modifications, which can be achieved by reducing the specified minimum yield strength, the main strengths of the approach are the fact that only limited pipeline modifications are required, as only new hydrogen-adapted recompression and gas pressure regulation stations are installed. Furthermore, material fracturing can be diminished in the case of static load operation. However, the increased crack growth will have a negative impact on the material strength and thus on the O&M cost of the pipeline. In the case of coating, the main strength is the coverage of the pipeline with a specific protection layer against hydrogen-induced degradation effects. Metal surface coating is a well-established industrial process and there are already in situ coating solutions for smaller distances. In such a case, the coating of long pipeline segments would require the excavation and deconstruction of existing NG pipelines, which would significantly add to the complexity and costs of reassignment.

In the case of the pipe-in-pipe approach, the benefits of the two specific pipelines can be combined where the outer pipeline (existing NG pipeline) would provide a mechanical safety barrier and the inner pipeline would be designed specifically for hydrogen delivery. This approach, however, is capital-intensive, as additional installation within existing pipelines would be required. Such a procedure would likely require pipeline excavation that significantly increases the complexity and cost of the pipeline reassignment.

Hydrogen blending in existing pipelines

One option for transporting hydrogen is to blend hydrogen with natural gas in existing natural gas pipelines. Historically, there have been many cases of utilizing hydrogen-rich town gas (50-60% H2), which was abandoned in favor of natural gas in the 1960s. Currently, different countries make use of hydrogen gas admixtures for natural gas of up to 10% vol, which can be further increased if heating devices and natural gas turbines and compressed natural gas vehicles, which currently allow a maximum of 2% vol, are adapted for higher hydrogen concentrations. A comparable large-scale change in consumer devices was already observed during the transition from town gas to natural gas in the 1960s, as well as during the ongoing shift from low- to high-caloric natural gas. The upper blending limit depends on the tolerance of the various components in the delivery system as well as the tolerances of the various gas consuming equipment within a network area[2].

To implement H2 blending, several complex measures are necessary. A blending level up to at least 20 percent by volume is technically achievable, but the feasibility of different blending levels depends on factors such as the origin of the natural gas the hydrogen would be blended with. Apart from this, there are still many uncertainties regarding (long-term) material sensitivities (pipes, devices, etc.) in particular regarding reduced lifetime when hydrogen is present which require further investigations. At the distribution networks level, today's blending levels would be limited mostly by the presence of CNG refueling stations due to the 2% hydrogen admixture limitations of gas-fueled cars. But in general, requirements for infrastructure adjustments are lower for many distribution networks. On the other hand, for transmission networks, hydrogen blending can introduce challenges for directly supplied industrial consumers, power plants and underground pore storage facilities. Here de-blending demands can occur at network nodes and directly supplied hydrogen sensitive consumers. For the same amount of hydrogen,

[2] Within standard EN 16726 from 2019 it is stated: "At present, it is not possible to establish a limit value for hydrogen that is universal for all areas of European gas infrastructure, and therefore a case-by-case analysis is recommended." Besides the technical sensitivities of gas infrastructure components described below, calorific value, Wobbe index and relative density also affect the blending capacity for hydrogen in natural gas networks. A hydrogen admixture of more than 10% requires individual testing in order to comply with relevant thresholds see for example technical rule G 260 in Germany [23].

opting for the approach of on-site blending at i.e. industrial sites, rather than pipeline blending and separation, would reduce the need for de-blending measures in the natural gas grid.

Blending levels up to 5% still show modest price increases for all customer groups. However, it must be considered that the introduction of hydrogen blending in one country or state would force almost all the other neighboring countries and regions to also take adjustment measures due to cross-border trade and supply security. In contrast to low blending levels, higher levels would lead to substantial price increases (especially for industrial customers, such as turbines which are sensitive to the combustion temperature of the fuel)[24]. A recent study for the European gas grid, indicates that an early gas network conversion to achieve over 20 Vol-% blending would be expensive [25]. A low costs long-term conversion to 20 Vol-% would theoretically be possible at by introducing "hydrogen ready" standards for new end-user equipment. However, to step-up the hydrogen volume from 20 Vol-% to 100 Vol-% in the period well after 2040 would be too late to meet climate targets.

Hydrogen blending: Technical Considerations

Hydrogen possesses an energy content per unit volume only about 1/3 that of NG. However, hydrogen flows through a pipeline at a faster speed than NG because it is a lighter molecule with lower viscosity. These factors partially make up for hydrogen's lower energy content, so that the pipeline energy flow rate for hydrogen is 20-30% less than for NG [26]. Compression electricity or other energy requirements for pure hydrogen are roughly three to four times those for NG.

For example, replacing 10% to 20% of the volume of NG with hydrogen reduces the overall volumetric energy content of the blended gas by approximately 7% to 13%. Approximately 3.6% to 7.7% of the energy flow in the pipeline is hydrogen, with the remaining energy flow (96.4% to 92.3%) being NG. For each GW of gas energy carried, 0.04 to 0.08 GW is hydrogen, and 0.96 to 0.92 GW is NG. Lower energy flow rates for blends can be compensated by increasing pipeline pressure, up to limits.

Accordingly, blends of up 10% into the transmission and distribution pipelines are generally possible without many technical constraints or concerns. In the case of plastic or PVC pipelines, an admixture of up to 100% is technically feasible [24]. However, in the distribution network, main limitation is created by the domestic gas piping and gas metering, as additional investments may be required to adapt these components to accommodate larger amounts of hydrogen. For reference, currently process gas chromatographs capable to operate with up to 25 Vol-% of H2 are available on the market [27].

As for compressors, studies have shown that depending on the type of the compressor, the compressors can continue to operate without substantial modifications up to 10% (by volume) hydrogen. Furthermore, it is estimated that the compressor housing can be retained as is for blends of up to 40%. However, for higher blends of hydrogen the compressor has to be replaced [25]– [27].

In case of underground storage, there are two main types of gas storage, namely pore storage and salt cavern storages. In former case, hydrogen is a good substrate for sulfate-reducing bacteria, which increases the risk of bacteria growth, which in turn will lead to formation of hydrogen sulfide and thus to hydrogen consumption. In case of salt caverns there are no such issues, thus blending of up to 100 vol% is feasible.

When considering the blending to the gas system it is paramount to also consider the limitation on the consumer side, especially gas burners and turbines as well as industrial application. In case of gas burners, blending of up to 10 vol% is expected to not cause any long-term problems for the equipment, however, higher percentages will required modifications and other measures [30]. Moreover, to mitigate the risk of explosion due to flashback behavior of the gas equipment, tests for approval in EU require safe operation with up to 23% hydrogen, indicating that gas burners are in principle prepared to accommodate higher hydrogen concentrations. It is worth noting that currently hydrogen content in natural gas lies typically somewhere between 0.02-0.05% [31].

Industrial applications using natural gas for their processes have two main requirements for its feedstock, it needs to have consistent gas quality and produce stable flame temperature. The former requirement is especially relevant for the chemical industry which relies upon designated chemical composition of the feedstock used in the processes. In case of the latter, the stable flame temperature is required in high temperature processes such as ceramics and glass production to prevent damage to the furnaces and other equipment. Turbines, can also be considered as a high temperature process, thus currently depending on the manufacturer only ca. 1-5 vol% of hydrogen content can be processed in the turbine. It is estimated that existing turbines could potentially be refurbished to accommodate up to 30 vol% hydrogen. However, higher hydrogen concentrations will require replacement of the combustion chamber of the turbine. To sum up, note that there is no unique limit for a general blending cap for hydrogen-natural gas mixtures. From the technical perspective, the upper blending limits essentially depend on the tolerances of the various gas consumers or customers within a network area. Table 4 below summarizes the feasible amount of blended hydrogen, which does not require notable modifications.

Table 4. Summary findings of the initially available blending levels of hydrogen in the natural gas system

System element	% of hydrogen	Comment
Transmission pipelines	<10%	
Distribution pipelines	up to 100%	Polymer pipelines
Metering	up to 25%	
Compressors	<10%	
Gas storage	up to 100%	Salt caverns
Gas burner	<10%	No modifications required
Gas turbines	1-5%	Depending on the manufacturer
Industrial use	<1%	Especially chemical and glass industries

Given the sensitivity of various gas consumers to hydrogen and potential goal to use hydrogen for fuel cell vehicles deblending measures are required. One option can be the methanation process, which would use CO_2 to convert the blended hydrogen to methane. Such an option can be beneficial for industrial consumers that have a local CO_2 source or can utilize its own CO_2 emissions. However, this approach implies low costs for CO_2 separation at a sufficient purity, availability of a methanation plant, and low energy costs required to operate the high temperature process. Research suggests that such synthetic methane could cost up to 79$/MWh[3] (22$/GJ) [32]. Alternatively, hydrogen can be separated from the gas stream with various means such as membranes or pressure swing adsorption. It is estimated that deblending of hydrogen could cost between 0.53-2.1 $/kgH2 [19], [24], [33], or possibly as low as 0.3 using advanced separation technologies . Moreover, the separated hydrogen is at atmospheric pressure, thus further utilization of hydrogen in fuel cell vehicles would require additional recompression back to 350/700 bar level. Industrial consumers of hydrogen such as ammonia and methanol production as well as refineries do not require high hydrogen pressure, thus no additional pressurization for the utilization of deblended hydrogen would be required.

Pipeline development: legal and regulatory issues

Natural gas and hydrogen pipelines have comparable scoping requirements related to safety and environmental impact assessments. However, the specific approval procedure may vary depending on the type of substance to be transported, the location (such as zoning type), and the diameter and length of the pipeline. As an example for the typical structure of the scoping process for a pipeline project in Germany is shown (see Figure 5). For a pipeline greater than 40 km long and 300 to 800 mm in diameter, the environmental impact assessment act requires a more complex infrastructure planning approval procedure than for shorter, smaller pipelines. However, if the smaller projects are determined to have a major impact on the environment, the complex planning procedure is recommended to be followed.

[3] Euro to Dollar conversion rate 1.05 at the time of writing

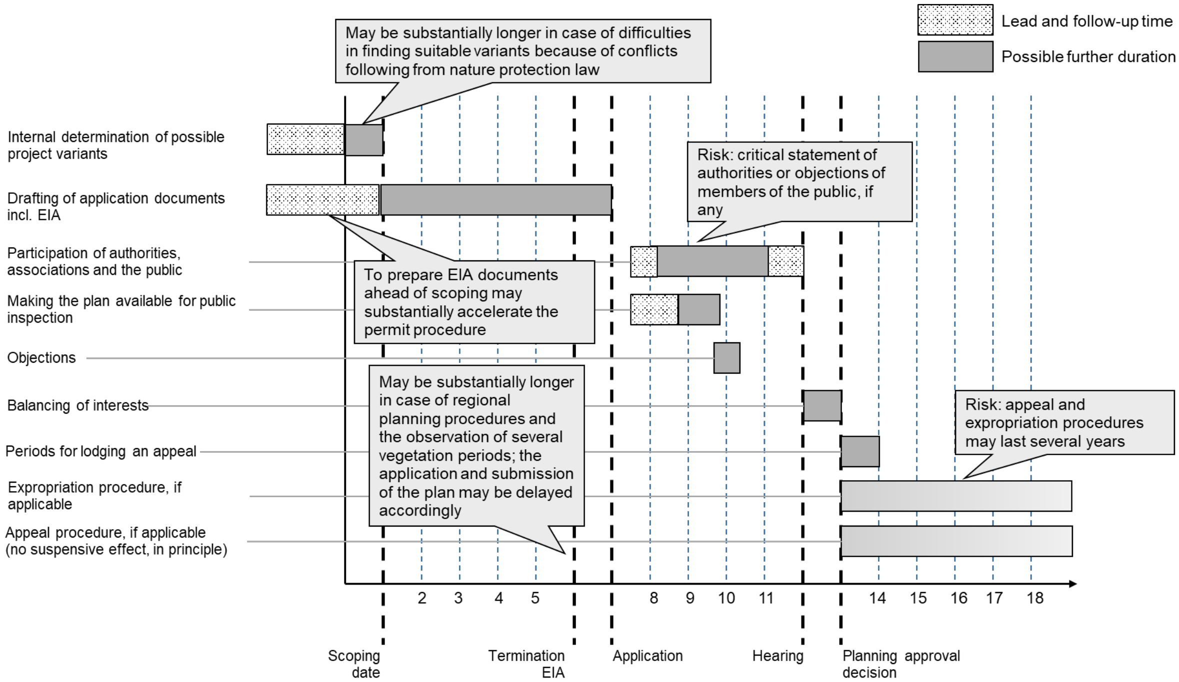

Figure 5. Overview of exemplary environmental impact assessment process of a pipeline project (months per phase)

Scoping starts when the applicant submits a complete plan to the competent authority for the licensing procedure. Through scoping the decision on EIA requirement is taken and the public hearing process starts for the consideration of opinions of affected stakeholders from the project. There are, in general, 18 months required for a basic approval of any project. However, regional and local level requirements can cause delays when various issues arise. . In case of the US, hydrogen pipeline safety is currently regulated by US Department of Transportation Pipeline & Hazardous Materials Safety Administration (PHMSA). Should larger hydrogen pipelines be built in the future, the planning, permitting and regulation will likely be integrated into the established regulatory bodies for natural gas pipelines, as it is already the case in Europe [34]. Under the U.S. Natural Gas Act, the Federal Energy Regulatory Commission (FERC) is overseeing the permitting of the pipelines [35]. The approval process encompasses five main stages, including the market assessment, where the demand for the project is assessed. Additionally, communication with local landowners can be started. This step is followed by FERC pre-filing, where the first discussions regarding permitting process and associated requirements with the relevant regulatory bodies is started in order to minimize the effort during the formal FERC application. It is stated that this step typically takes from 6 to 12 months [36]. Then a formal FERC application is submitted, where an environmental assessment of environmental impact statement is prepared. Furthermore, alternative routes to mitigate the environmental impacts are assessed. Depending on the project size this step can take from more than a year to several years [36], and thus is comparable to the stated example for Germany. After the successful conclusion, FERC certificate with the list of required permits is issued. Only after all the required permits for the project are obtained, can the pipeline developer begin with construction. The time required to obtained the permits largely depends on the size and the complexity of the project; relevant governmental agencies are US department of transportation, US department of the interior, US environmental protection agency, US forest service, national marine fisheries service, advisory council of historic preservation and US army corps of engineers [35]. Thus the pre-filing and the formal application process takes from 1.5 to 3 years. If we assume additional 6 months for market assessment and permitting respectively, the total time required to prepare a pipeline project for construction is between 2.5 to 4 years if no major protests, lawsuits or delays are encountered, which can extend the project permitting phase by several additional years.

Regulation of hydrogen pipeline construction and operation

There are existing industrial piping norms in the USA and EU for hydrogen pipelines that describe the technical side of the pipeline construction according to the state of the art practices and technologies [13], [14].

Several general challenges of regulation for hydrogen pipelines typically exist or can be anticipated. Pipeline safety regulations in most countries is generally geared towards transport of natural gas, which likely will not be appropriate to address the risks of hydrogen transport. Main areas of concern are pipeline steel materials and welding techniques required to facilitate secure long-term hydrogen transport. Without a clear regulatory framework for these issues, case by case studies will be required, thus increasing the complexity and time needed to implement such project.

For a blended hydrogen in natural gas transmission pipelines, it will be a challenge to facilitate cross-border flows among different countries or even states within a country due to the lack of consistent quality and interchangeability standards for various levels of blended hydrogen [37]. Furthermore, the questions of tariffs for blended hydrogen will need to be clearly defined in the regulation. In case of pipeline reassignment, an often contested question is the recovery of the reassignment costs of the pipeline, as such projects are usually undertaken regulated by grid operators financing their operations via natural gas grid tariffs [38]. Another key point for discussion for new or reassigned hydrogen pipelines is the conflict between often vertically integrated nature of the early hydrogen supply chains and general tendency of the policy makers to avoid the creation of monopolies and to decouple production and transport of energy, as it is the case for electricity and natural gas.

Hydrogen quality requirements of the consumers

The different requirements of the individual components along the supply chain regarding the state and purity of hydrogen require purification, compression, and liquefaction. The selected way of hydrogen storage is amongst the most important variables defining the required processing steps. Electrolytic production of hydrogen is generally facilitated between 1 and 20 bar, while hydrogen fuel cell applications for transportation operate at 350-700 bar. This pressure difference creates a significant pressure differential that must be bridged. Moreover, the high-pressure components of the hydrogen supply chain, such as high-pressure pipelines and 500-bar trailers, add even further constraints to the design of the supply chain.

Hydrogen purity requirements are primarily defined by the final hydrogen consumer's hydrogen quality constraints. The polymer electrolyte membrane fuel cells (PEMFCs), which are the most common type of fuel cells among the transportation applications, have a 99.97% purity requirement for hydrogen with orders of magnitude higher limits for individual contaminants such as O_2, CO_2, and H_2O [39].

The levels of the required hydrogen purity vary among the different industry segments (see Table 5 and Table 6). Hence, varying purification needs for the demand applications in the specific industry have an impact on the final hydrogen delivery cost. The purity requirements range from 99.95% to 99.995% for general industrial applications to 99.999% and 99.9997% for semiconductors and special applications of gaseous and liquid hydrogen, respectively [40]. Thus, the majority of hydrogen is consumed at 99.95 % purity levels in general industrial applications which are for the most part refineries and ammonia production plants. Furthermore, the verification of hydrogen quality varies between the physical state of hydrogen (gaseous or liquid). Due to no widespread applications, no standards on purity requirements were found for hydrogen usage for high temperature heat applications.

Accordingly, industrial applications have requirements for hydrogen purity comparable to PEMFCs used in the transportation sector, leading to high purity requirements for the hydrogen supply chain. Requirements for high temperature heat applications can be lower, however, in order to utilize the network effects the infrastructure would need to be designed to meet the requirements of all consumer segments. The stated high purity requirements for hydrogen of the existing hydrogen consumers increases the costs of processing the hydrogen, especially in the case of hydrogen blending where additional investment for deblending of hydrogen is required.

Table 5. Classification of gaseous hydrogen purity levels [40]

Quality Verification Level	Typical Uses	Hydrogen purity
B	General industrial applications	99.95%
D	Hydrogenation and water chemistry	99.99%
F	Instrumentation and propellant	99.995%
L	Semiconductor and special applications	99.999%

Table 6. Classification of liquid hydrogen purity level [40]

Quality Verification Level	Typical Uses	Hydrogen purity
A	Standard industrial applications, fuel and standard propellant	99.995%
B	High purity: industrial, fuel and propellant	99.999%
C	Semiconductor	99.9997%

Interface between pipelines and refueling stations (pressure/storage issues)

There is also a possibility to supply hydrogen directly with high pressure pipeline from the transmission pipeline. Normally, gaseous hydrogen in the pipeline is transported at a pressure of 20-100 bar. In case of direct connection the refueling station, the installation of a daily storage can be avoided. However, the requirements for the compressors remain similar or are even higher. The pressure in the pipelines is typically lower than that used in the trailers (300 - 500 bar) or stationary storages at site with up to 150 bar. One possibility is to compress hydrogen at the production site or connection to transmission pipeline up to refueling pressure and transport it by high-pressure pipeline. This allows a high capacity at the hydrogen refueling station. This eliminates the need for a station storage and compression, which are among the largest and most expensive components of hydrogen refueling stations. However, a direct connection of the refueling station to the pipeline requires stable pressure levels in the delivering pipeline if the storage at station is to be avoided. The prospects for creating this pressure stability throughout the system in order to provide reliable refueling performance are unclear, and stations currently ensure this reliability by on-site pressurization or liquefaction.

In case of liquid hydrogen refueling (or as an approach to rapid refueling even for gaseous hydrogen-fueled vehicles), a liquefaction unit at the refueling station, or nearby, would be required. Liquefaction typically consists of two streams, the cold cycle, where the refrigerant is flowing and the gas stream, where the gas to be cooled is flowing. The pressurized hydrogen from the pipeline could feed the gas stream and avoid the installation of an additional compressor, however this would require a stable pressure in the pipeline. Liquefiers in operation today can be categorized, by referring to the cold cycle type, into reversed helium Brayton and hydrogen Claude cycles. The former is typically employed for smaller liquefaction capacities due to lower investment costs related to the use of standardized helium screw compressors. Larger liquefiers, up to 15 t/d, or higher, are normally designed with a hydrogen Claude cycle. These are characterized by the use of more expensive reciprocating piston compressors, but savings in operating expense (OPEX) due to a higher energy efficiency and lower refrigerant costs. Hence, an onsite liquefaction unit at the station would require either making compromises for efficiency, thus increasing the costs, or be built larger in order to reach the necessary scale effects and higher efficiency, but would also require more space at the site. This could be addressed by creating liquefaction terminals at a larger scale, with “last mile” delivery to stations via hydrogen liquid tanker trucks, but this introduces the additional truck delivery cost.

Hydrogen storage throughout the supply chain

The fact that hydrogen delivery uses a chemical molecule instead of electric power for energy transport, the system is constituted of components that inherently provide varying degrees of storage capacity, making the system inherently more flexible to balance, and providing more resiliency option to mitigate supply interruption risks and other external factors. Besides the dedicated storages for long-term seasonal hydrogen storage, the hydrogen supply chain encompasses various elements, that can act as additional buffers in the system, such as hydrogen ships, hydrogen pipelines and refueling stations. The latter two will be elaborated more in the following sections.

Storage at refueling stations

In order to facilitate a high security of supply and faster refueling, hydrogen refueling stations typically include a storage unit, that is used to store hydrogen between the deliveries to the station. Alternatively, in case of on-site hydrogen production, a storage unit can be installed in order to increase the flexibility of the electrolysis unit to operate at more optimal electricity costs. This storage can cover the demand up to several days. In case of supply via pipeline, some on-site storage may still be needed to facilitate fueling at desired rates. In principle the storage at the refueling station can be built bigger, especially if the particular station serves as a regional hub, from where hydrogen is further distributed. However, in practice, as hydrogen refueling stations are predominantly installed in the area of an existing refueling station and hydrogen storage requires additional security measures, such as increased distances from buildings etc., the capacity of the storage is often limited by the available space at the site.

Storage with pipelines

Besides the inherent hydrogen storage in the trailer delivering hydrogen, which can even be offloaded at the station to serve as stationary storage, hydrogen pipelines offer another buffer storage in the form of "line pack," which is essentially the difference in pipeline capacity between minimum and maximum operating pressures on the pipeline. Storage capacity of the pipelines can be assessed with the help of the mass flow capacity of the pipeline. Mass flow can be described in dependance to the diameter of the pipeline, gas velocity and the density of hydrogen, with the equation:

$$\dot{m} = v * \rho * \pi * \frac{D^2}{4},$$

where $\dot{m}$ is mass flow, v gas velocity, ρ gas density *D* diameter of the pipeline. For the assessment of the storage capacity let us assume a gas velocity of 10 m/s and pipeline diameter of 39 inch, however as only the density of hydrogen will change in accordance with the allowed pressure variation, these values do not affect only the relative magnitude of the storage capacity in the pipeline. For the variation of the pipeline pressure it is assumed that the pipeline is usually supplying hydrogen at 50 bar, but for storage reasons the pressure is increased up to 100 bar, thus providing pressure difference for storage of 50 bar. After the increase of pressure, the density of hydrogen changes from ca. 5 kg/m3 to ca. 8 kg/m3 at approximately 15°C. Consequently, the mass flow capacity changes from originally 39 kg/s to 63 kg/s at the increased pressure of 100 bar. Thus the pressure increase from 50 bar to 100 bar adds additional 60% mass flow capacity for the pipeline. From perspective of storage volume, a 300 km long pipeline with 39-inch diameter would have a total volume of 235500 m^3. A pressure increase from 50 bar to 100 bar would allow to store additional 706500 kg of hydrogen, which at delivery rate of 39 kg/s will be used up in 5 hours. According to this simple estimation, the pipeline could then store a small part of its daily capacity, enabling it to absorb the immediate supply fluctuations and act as a buffer storage to alleviate the short-term imbalance between supply and demand. However, for storage over longer periods of time, substantially larger pressure changes in the pipeline would be required. However, regular large pressure swings would be detrimental to the material integrity and would require substantially larger investments into the system to retain the pipeline system security. From this perspective it is much more efficient to include supplemental storage facilities on pipelines when significant or long-term variations in supply and/or demand are expected.

Comparing deep storage (caverns) with LH2 and GH2 storage options (qualitative)

Pure hydrogen can be stored in specialized steel or composite containers in a compressed, liquid state or, alternatively, compressed hydrogen can be stored in underground facilities.

For pressurized gas storage, a container is required that can withstand the differential pressure of the gas and the ambient pressure. This container has a minimum and maximum pressure, which describes the maximum mass of gas that can be stored (working gas). Depending on the minimum pressure, a certain amount of gas remains in the containment, which is referred to as cushion gas. There are different concepts depending on the size unit.

For small-scale storage, such as in a vehicle, or for stationary storage of hydrogen at a hydrogen filling station, cylindrical pressure vessels are used. These are divided into four types. The basis of all four types is a gas-tight pressure vessel (liner), which is made of metal (type I-III) or plastic (type IV). Geological underground storage facilities are used for large-scale storage. These are divided into pore storage facilities, such as depleted oil and gas fields or aquifers, and cavity storage, such as salt or rock caverns. Gas contamination is still an unsolved challenge for porous storage systems. In addition, rapid load changes are not possible and there is a high cushion gas requirement. Rock caverns require high investments for excavation and also have only limited occurrences. Salt caverns are the leading solution for underground hydrogen storage today.

The high storage capacity and relatively low costs of underground storage make it an especially attractive solution for seasonal renewable energy variations. Gaseous and liquid storage options, by contrast, are more expensive and thus more suitable as buffer systems at, for example, hydrogen refueling stations. The utilization of underground storage in industrial facilities since the 1960s has already proven the technical feasibility of GWh-scale underground hydrogen salt caverns. However, despite large potential in Europe and some other regions, the geological limitations of the required rock formations for salt caverns and porous rock diminish the global availability of underground hydrogen storage (and multiple media may compete for underground deposits, such as compressed air, CO_2 and hydrogen itself).

Example scenarios for pipelines

To estimate the order of magnitude of the economic impact of various alternatives for hydrogen transport through pipelines a scenario is selected where an industrial hydrogen consumer compares transporting electricity from a remote renewable source to feed an on-site electrolyzers versus remote hydrogen production and transportation by hydrogen pipelines. Costs of electrolysis, compression, storage and local delivery costs are disregarded in this comparison as their costs are close to identical in both cases when the same technologies are applied. To consider a large-scale, long-distance case a transport capacity of 1 GW and 5 GW over 300 km and 1000 km is assumed. For hydrogen transport, the previously discussed options of dedicated hydrogen pipelines, reassigned hydrogen pipelines as well as hydrogen blending are considered. Pipeline diameters for 1 GW and 5 GW capacity are estimated to reach approximately 300 and 500 mm respectively. Due to the perspective of the hydrogen consumer, the cost of deblending hydrogen is also considered in the assessment for 1 GW and 5 GW capacity of deblended hydrogen. Additionally, for reference we consider electricity transport via high voltage cables or overhead lines with 1 GW and 5 GW capacity. To allow the comparison of the transport modes at same name plate capacity, we assume that energy gap due to the losses of the on-site electrolysis is balanced out with the locally sourced electricity. As this analysis does not include an analysis of a specific geography for new hydrogen pipeline, nor for new AC or DC power lines, no regional specific cost for rights of way is included in the calculation. The underlying assumptions for the techno-economic assessment are presented in Table 7.

Table 7. Techno-economic data of energy transport options [18], [19], [41]–[43]

Assumption	H2 pipeline	Reassigned pipeline	H2 blending (10%)	AC Line	DC line
Capacity factor	0.8	0.8	0.8	0.8	0.8
1 GW invest [M$/km]	1[4]	0.35[5]	0.09	1.9*; 2.3**	2.5*; 1.1**
5 GW invest [M$/km]	2	0.7	0.09	9.5*; 11.5**	12.5*; 5.5**
PSA deblending [US cents/kWh]	None	None	1.5	None	None
O&M[6] [%]	5	5	2	0.1	0.1
Lifespan [year]	40	40	40	40	40
Discount rate[7] [%]	8	8	8	8	8
Efficiency [%]	99.95	99.95	99.95	96.5	96.1

*specific cost for 300 km; ** specific cost for 1000 km.

The resulting costs of energy transport are depicted in Figure 6 and Figure 7. From the first Figure 6 one can derive that on the one hand due to the scaling effects a five-fold increase of the capacity leads to approximately 60% lower specific transport costs for the same distance. On the other hand the distance has a linear effect on the hydrogen transport cost. Other factors may also affect the scaling and unit costs.

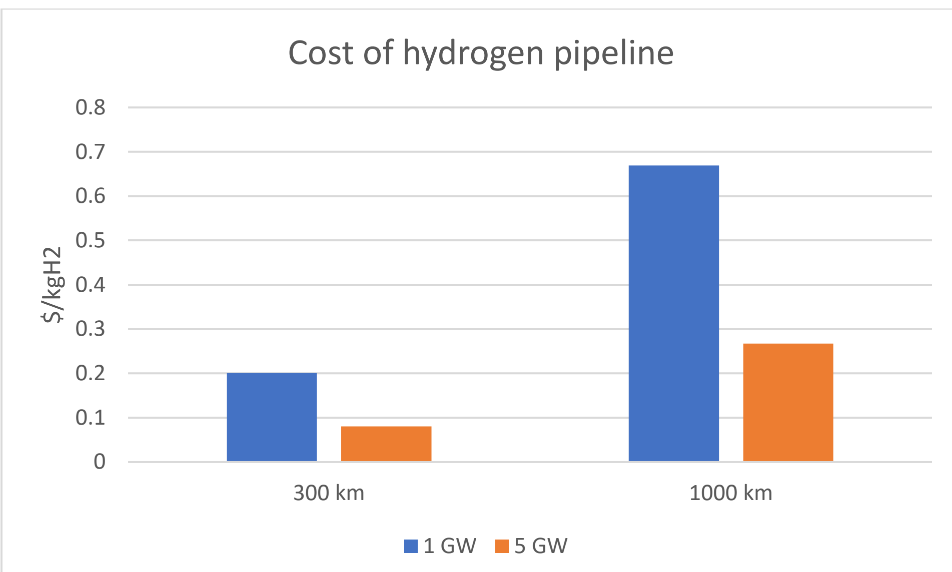

Figure 6. Cost of hydrogen pipeline for small (1GW 300 km) and large scale (5GW 1000 km) energy transport

First, one can observe from Figure 7 that with 1.54 ct/kWh hydrogen blending is the most expensive option among the pipeline options, as all blending related expenditures are allocated to the amount of

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[4] Capital and O&M costs of compressors are included, green electricity cost at 60$/MWh
[5] Capital and O&M costs of compressors are included, green electricity cost at 60$/MWh
[6] Percentage of the capital cost
[7] Real discount rate

the transported hydrogen, in this case 1 GW and 5 GW. The estimated cost of deblending at the end-use point makes over 97% of the estimated transport cost, highlighting the importance of deblending for low blending levels. Accordingly, transport distance has very low impact on the total cost. As previously mentioned, higher blending levels than 10% will incur additional investment costs, which would come on top of the estimated cost. In comparison to blending, hydrogen can be transported via dedicated pipelines. In case of a new hydrogen pipeline, the estimated cost of transport reaches between 0.57-0.76 ct/kWh and is more than 40% lower than in the case of blending. Additionally, in contrast to blending, further market development and larger hydrogen volumes will decrease the cost rather than increase them, as scale economies can make hydrogen pipelines substantially cheaper. This can be observed when short and long-distance scenarios are compared, as three times higher capacity transported over 3.3 times larger distance increases the hydrogen pipeline cost only by 45%. Alternatively, an available natural gas pipeline can be reassigned for hydrogen, thus still utilizing existing assets while avoiding the expensive deblending process. Based on the estimates, a reassigned pipeline would cost ca. 0.2-0.26 ct/kWh and is more than 60% cheaper than an entirely new hydrogen pipeline and 80% less expensive than blending.

Alternatively, the energy can be also transported through electricity lines to produce hydrogen on-site. Most notable options for this approach are AC and DC lines with the costs ranging from 0.72 ct/kWh to 1.1 ct/kWh for 1GW over 300 km scenario. Thus the costs of the AC and DC lines are in range between new hydrogen pipeline and hydrogen blending, while the costs of a reassigned pipeline remain the most cost-effective alternative. At the same time pipelines offer additional hourly buffer storage, alleviating short-term supply and demand imbalances, while AC and DC lines would require additional battery storage solutions to achieve the same effect. In the long-distance scenario where the transport distance and capacity are increased to 1000 km and 5GW respectively, the costs of power line systems are comparable to or surpass the expensive hydrogen blending pathway. Accordingly, one can conclude that in case of available pipelines the reassignment option is the most cost-competitive option, while new hydrogen pipelines are competitive with AC lines for medium capacities and distances. Even though DC lines are optimized for large distance large capacity energy transport, DC lines remain substantially more expensive than even new hydrogen pipelines in both scenarios. Moreover, for larger energy flows costs of reassigned pipelines can be expected to diminish even further, thus making it a promising long-term solution for large scale energy transport. Finally, if the costs associated with rights of way were included, this would likely further favor hydrogen pipelines, since power lines typically have a higher footprint than new or reassigned pipelines.

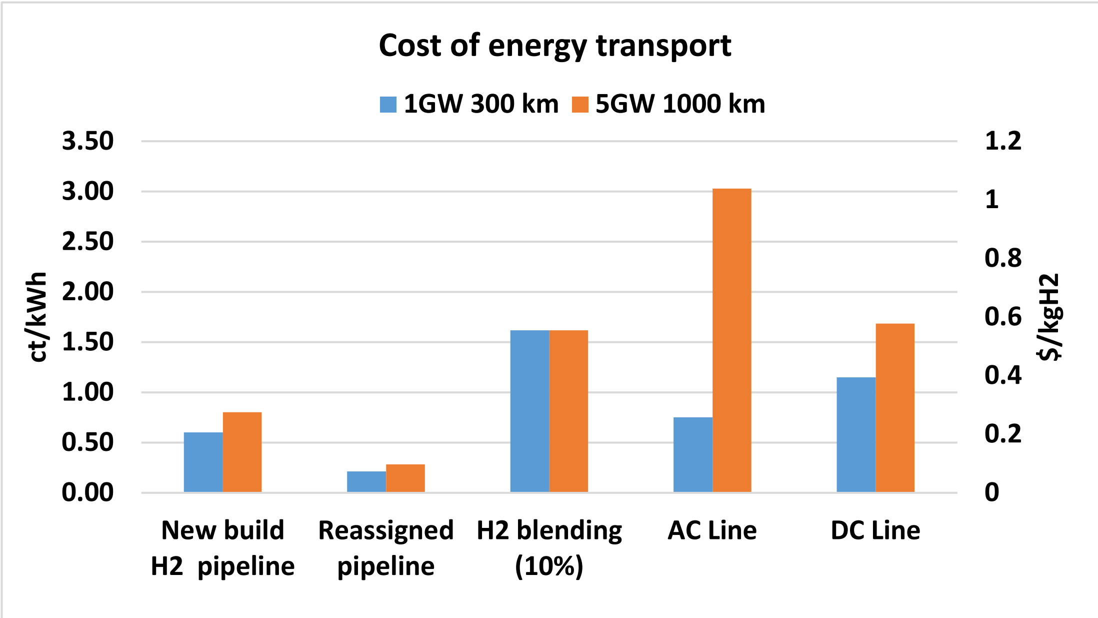

Figure 7. Comparison of energy transport options for 1 GW & 5 GW capacity over 300 km and 1000 km[8]

Given the fact that during the introduction phase lower pipeline utilization can be expected, the impact of the capacity factor is considered (see Figure 8). As shown, due to higher capital expenditure for new hydrogen pipelines the sensitivity to the capacity factor is significant. With a low capacity factor of 0.3 (30% utilization), new hydrogen pipelines cost is about 1.5 ct/kWh, approximately the same as hydrogen blending case in Figure 7 which was identified as the most expensive option for the short-distance energy transport. By the same token, the low capacity factor of a reassigned pipeline leads to similar costs to a new hydrogen pipeline at 80% utilization, thus essentially allowing ca. 50% underutilization compared to a new pipeline. The observed cost increases due to lower utilization already include the lower compressor operation cost. This finding also underscores the suitability of pipeline reassignment during the introduction phase of the hydrogen market. This feature is important as natural gas pipelines for reassignment will typically be substantially larger than what is initially required for hydrogen transport.

[8] Costs for hydrogen blending include the deblending at the end-use point. All expenditures are allocated to the amount of the transported hydrogen, i.e. 1GW and 5GW.

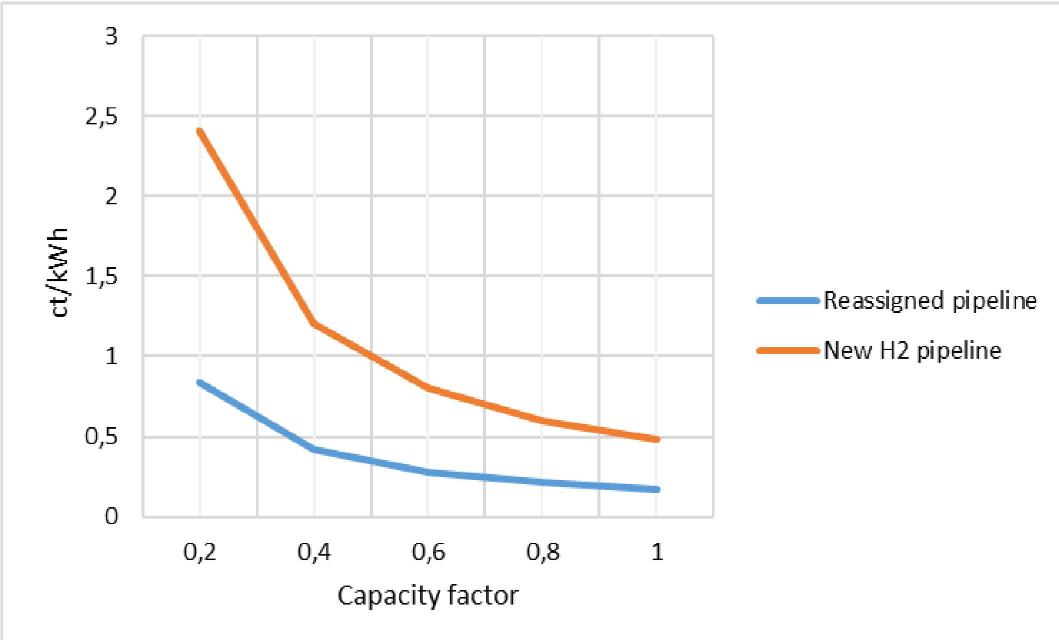

Figure 8. Cost of hydrogen pipelines in relation to the capacity factor for short-distance scenario at 1 GW and 300 km

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