Hydrogen Storage and Transport: Technologies and Costs

February 27, 2024

Andrew Burke, Joan Ogden, Lewis Fulton

Institute of Transportation Studies, UC Davis

Simonas Cerniauskas

Consultant

UCDAVIS
Institute of Transportation Studies

Reference No. UCD-ITS-RR-24-17

Contents

Executive Summary

This paper evaluates various options for storing hydrogen and assesses their cost per kilogram stored, and the cost of the hydrogen dispensed. The storage options considered are line-packing (increased hydrogen density and pressure) in pipelines, underground storage in salt caverns, liquid storage (LH2) and high-pressure gaseous storage (CH2) in tanks. We find that cost varies both by technology and how it is used, especially the duration of storage. The need for and availability of pipelines is also a key consideration. Overall we find that:

- For pipeline transported hydrogen:
  - Line packing: should be preferably used for very short duration of storage.
  - Salt caverns: all other durations in case geographically available, especially long-term storage as no other option offers such a high cost-effectiveness.
- For truck or trailer transported hydrogen:
  - GH2 tank: should be utilized for short duration (e.g. daily) of storage as a buffer.
  - LH2 tank: can be used as daily or weekly storage and for longer term storage where caverns are not available.

The levelized cost ($/kgH2) of the storage for each option was calculated for a typical application. Key findings are:

- For **line packing** in 36 and 48 inch diameter pipelines of 100 km length, the effective mass of hydrogen that could be stored for use in a day is 150-300 tonnes, and the levelized cost is $0.05/kg or less. This required the operator of the pipeline to vary the peak pressure to meet varying customer demand. This cycling could reduce the lifetime of the pipe.
- For **salt caverns**, the typical salt cavern case studied was for storage of 500 tonnes of hydrogen. This costs about $18M ($36/kgH2) to prepare. The levelized cost of storing the hydrogen in the cavern would be $1.2/kg, if it is stored for 120 days (4 months) and only $0.15/kg if stored for 15 days on a regular basis.
- For **pressurized storage** (such as at refueling stations) using high pressure tanks suitable for a 1000 kgH2/day station, the tank might store 1000 kg and cost $600,000. The hydrogen dispensers at the station would be connected to the tank, so all the hydrogen dispensed at the station would be fed through the tank. Hence the tank could store and feed 1000 kg x 365 days of hydrogen annually to vehicles for refueling. The resulting levelized storage cost at full utilization would be about $0.16/kgH2 with additional 0.4 $/kg for compression.
- For **liquid (cryogenic) storage** of hydrogen in large, highly insulated tanks, the cost of the storage tank is $30-50/kgH2. If the hydrogen is stored for one week, the levelized cost of storage would be $0.055-.091/kgH2 with additional 1.2 $/kg for liquefaction in large-scale plant.

This study indicates that the contribution of the cost of providing storage to the cost of the hydrogen dispensed in applications requiring short, daily storage is low and the cost of long duration, seasonal storage is much higher, mainly due to the time component. The storage costs are summarized in Table ES-1.

Table ES-1: Summary of hydrogen storage options and costs

Storage technology	Typical duration of storage	Tonnes of H2 typically stored	Levelized storage cost range ($/kgH2)
Line packing	1 day or less	100-300	0.05 or less
Salt cavern	2-4 months	500-1000	0.6-1.2
Above ground pressurized tank, GH2	1-2 days	0.3-1.0	0.3-0.5
Above ground liquid tank, LH2	1-2 weeks	5-10	.06-0.12

Storage costs in Table ES-1 do not explicitly include costs for hydrogen compression or liquefaction.

The typical amounts and cost of storage clearly varies considerably by technology, creating a set of niches for each one. In general, salt caverns typically can hold hundreds of times more hydrogen than above ground storage tanks. However, for the length of time indicated in the table, we do not find storage caverns to be less expensive than other approaches.

While this paper provides an overview and some specific comparisons of hydrogen storage technologies, additional investigation and analysis is needed. This includes into the specific way that the duration of storage affects costs, as well as the number of uses (fills and re-fills) over this duration. Deeper analysis into new technologies that could cut storage costs, and estimating the combined costs of various combinations of components in systems, would also provide additional value to the estimates presented here.

Introduction

Hydrogen (H2) can be valuable as an energy carrier and storage medium, particularly for long duration, seasonal storage. Even on a daily use basis, hydrogen must be stored to create a secure supply. As shown in Figure 1, optimal energy storage approaches vary based on the required levels of discharge power and storage duration [1]. Storage options exist for hydrogen that cover wide ranges of charge/discharge times, duration of hold time, and quantity of energy stored [1, 2]. Hydrogen can be stored for a few minutes, a few hours, a few days, or a few months at relatively low costs. In this paper, the technologies for these options are studied and their costs evaluated. The technologies include line-packing in pipelines, underground storage in caverns, and storage in high pressure tanks. In most situations, the H2 must be transported into and out of storage. This will require either truck transport or a network of pipelines of various diameters and lengths, and the type of transport is linked to the storage system. In addition to the storage cost, the transport cost ($/kgH2) of the H2 will be important in determining its dispensed cost.

A challenge with fully renewable electricity systems is balancing electricity supply from wind and solar (which are not dispatchable) and electricity demand [3-5]. It is particularly difficult to balance supply and demand over weeks and months when resources and demand may vary considerably. As shown in Figure 1, converting excess electricity into H2 via electrolysis and storing the H2 for later reconversion to electricity is one of the few options available to balance supply and demand over weeks or months, particularly with a variable renewables-intensive grid [1, 4].

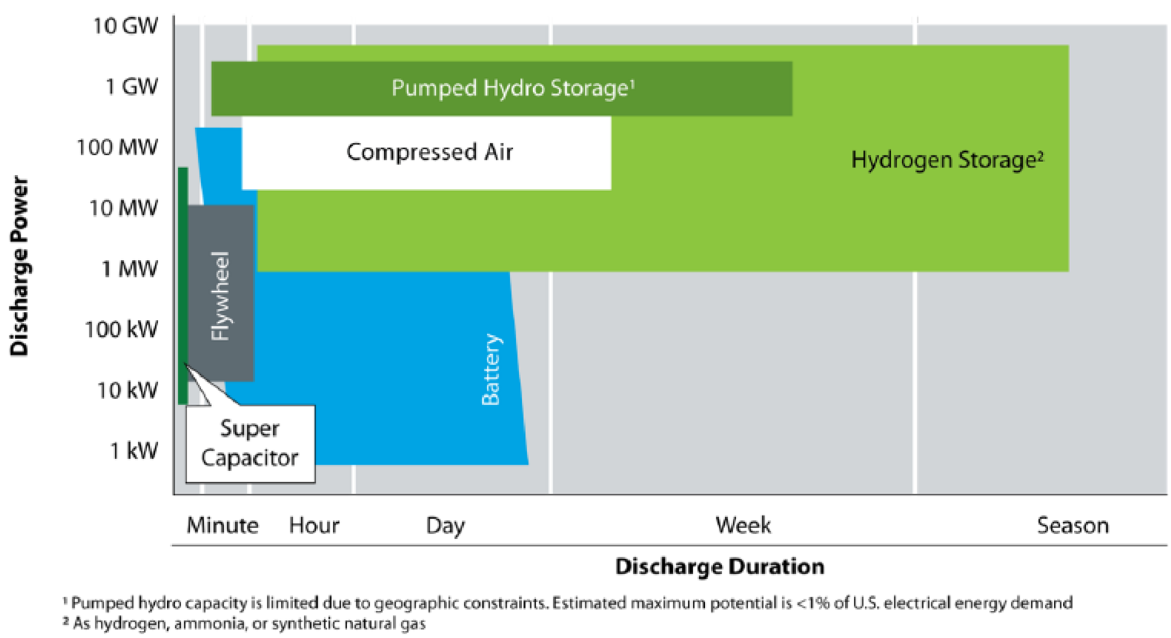


Figure 1: Optimal power and discharge-duration characteristics of energy storage technologies [1]

As shown in Figure 2, hydrogen may be stored near its production or where it is consumed, or both. Systems with a pipeline to transport hydrogen may not need storage at the end use location, since the pipeline itself provides storage [5]. We consider storage independent of location.

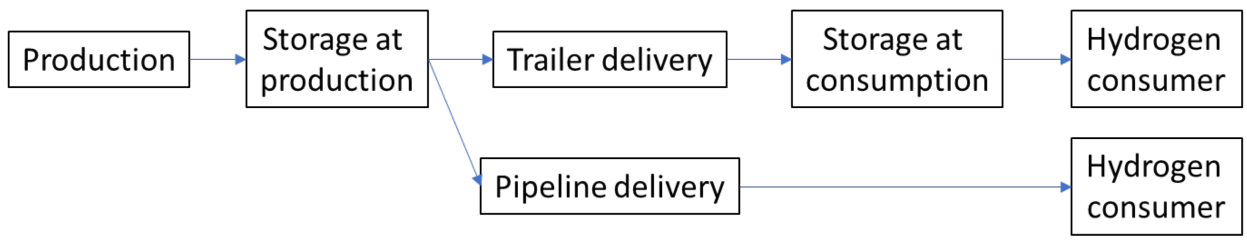


Figure 2: Basic overview of storage requirements in the hydrogen supply chain

Hydrogen can be delivered along two main supply chain routes. First it can be delivered via gaseous or liquid hydrogen trailers which provide discrete hydrogen transport one trailer at a time. To allow production and consumption of hydrogen while the trailers are on the road, this supply chain pathway requires storage at the production and consumption locations, largely decoupling hydrogen production and consumption. The second supply chain pathway utilizes continuous hydrogen delivery via pipeline to the consumer. Due to the continuity of hydrogen flow, the consumer can draw from the pipeline at any point of time and may not require any on-site storage, though this depends on stable operation of the pipeline network, with a continuous in-flow of hydrogen that matches the demand and keeps the system within the designated pressure levels. This poses a challenge for electrolytic hydrogen production from intermittent renewable electricity sources like solar photovoltaic (PV) and wind. Thus in such cases, storage at the production site is required. In cases of highly variable hydrogen demands, storage at the end use site may also be desirable to increase reliability.

Typical requirements for hydrogen storage applications can be derived from these two supply chain pathways. First, ensuring continuous supply in the pipeline requires balancing the hourly to daily intermittency of the electrolytic hydrogen production. An average hydrogen pipeline is expected to have a capacity of 100 MW to 5 GW, which would need to be balanced out with the appropriate discharge capacity of the storage. Due to the flexibility of the pipeline to operate within a certain pressure range, the pipeline itself can be utilized to balance the short intermittencies by temporarily increasing the pressure up to the maximum limit along the pipeline until it is discharged up to the lower pressure limit.

When truck delivery is utilized, storage is needed at the production and consumption sites. A single "tube trailer" (compressed gas delivery trailer) can transport 500 kg or more compressed hydrogen during a single trip [36] and can be a cost-efficient transport approach up to about 200 miles [37, 38]. However, such a distance (with the round trip and trailer fueling time) requires up to a day to complete. And for large stations, e.g. over 1-2 tonnes/day capacity, tube trailers become cumbersome and expensive, needing multiple deliveries per day. Highway truck stops are expected to have a capacity of at least 4 tonnes per day. Storage at stations can be either gaseous or liquid, with the choice potentially based on the needed speed of refueling customer vehicles. Liquid refueling systems (even into gaseous storage tanks on vehicles) can refill these tanks much faster than can gaseous systems, which is particularly important for large trucks. If liquid storage is used at the station, it is likely that hydrogen will need to be delivered as a liquid, and liquefied off site. Liquefaction is expensive and tends to be done in central locations at large volume, such as 15-30 tonnes capacity. The combined economics of liquefaction, trucking liquid H2, and storing it at the station, vs other options (such as a purely compressed gas truck system or a gas pipeline system) are complex and outside the scope of this paper.

In the electric system, the daily and seasonal variability of renewable power generation creates a potentially important role for hydrogen to store energy. It can be generated by electrolysis at times of excess capacity, stored, and then used to re-generate electricity via turbines or fuel cells during times of capacity shortfall. Electrolytic hydrogen supply in this context necessitates the ability to store hydrogen for days, weeks and potentially months. If hydrogen volumes are large, and months-long storage is needed, it may be economic to store the hydrogen in low-cost salt caverns, which may be far from the points of generation and use. Pipelines are the likely low-cost solution for this transport, since volumes may be several times greater than the identified capacities for the individual systems above. As shown in Figure 3, a storage discharge capacity in the range of 10 MW to 10 GW can be provided by line packing and underground storage, whereas pressure vessels are suitable within a one MW to a few hundred MW range. However, line packing and pressure vessels are not good long-duration storage options.

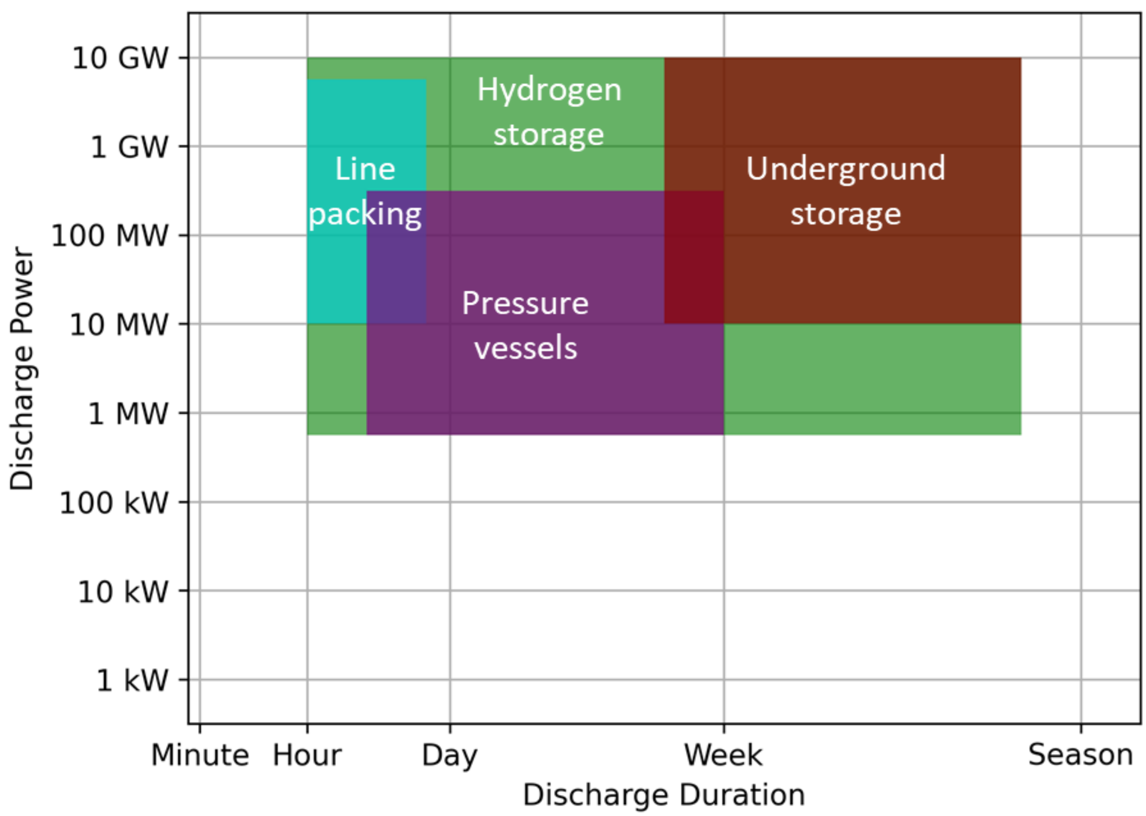


Figure 3: Storage duration and discharge power of hydrogen storage systems using data from [1]

The following sections discuss the characteristics of individual hydrogen storage options and relevant characteristics to the described use cases.

Pressure vessels

By increasing the volumetric energy density of gaseous hydrogen through compression, the necessary storage volume can be decreased. For instance, hydrogen has a density of 0.084 kg/m3 at 20 °C and 1.01 bar of pressure, while when hydrogen is compressed, this value rises to 7.80 kg/m3 at 100 bar of pressure. Further compression to 1000 bar results in a volumetric energy density of 49.9 kgm3, which is consistent with the less-than-ideal properties of hydrogen at high pressures [34]. Different types of compression and cooling require different compression work. The least energy-intensive method is isothermal compression, which theoretically results in 1.5 and 2.0 kWh of work per kilogram of hydrogen compressed to pressures of 253 and 1013 bar (250 and 1000 atm), respectively [34]. The power demand increases to 2.5 and 4.0 kWh/kg because in reality there are other losses, such as parasitic compression losses, and because the compressor station's overall energy consumption must be taken into account. This is equivalent to 7.5% and 12% of the hydrogen using lower heating value (LHV). The industrial gas handling, chemical, and oil industries, as well as a relatively large number of other industries, all successfully employ hydrogen compressors, which are currently considered to be state-of-the-art [39] [45].

The container used for compressed gas storage must be able to withstand the pressure difference between the gas and the surrounding atmosphere, with repeated pressurization events over time. The differential pressure of the working gas determines the maximum mass of gas that can be stored in this container. The container, which has a minimum and maximum permissible pressure, always contains some gas, known as cushion gas, depending on the minimum pressure. Numerous specific technologies exist, with choices depending on the size and specific role of the unit.

Cylindrical pressure vessels are used for stationary hydrogen storage at a hydrogen filling station or for small-scale hydrogen storage, such as in a vehicle. Serving as the foundation of various types of these gas-tight pressure vessels are four types of liner, which are made of either metal (types I–III) or plastic (type IV). This liner is partially (type II) or fully (type III) covered by a network of plastic fibers that have been impregnated with resin to provide the necessary strength.

Cryogenic storage

Another storage option is cryogenic liquid hydrogen. Because all hydrogen production methods first create gaseous hydrogen, liquefaction is an additional required step before storing hydrogen in cryogenic form, which raises a challenge of adding energy intensity. Although the theoretical minimal electricity demand of hydrogen liquefaction is 2.9 kWh/kgH2 [45] which corresponds to 8.7 % of the lower heating value of hydrogen, today's hydrogen liquefaction plants, however, operate at much lower efficiency in the range of 9 - 15 kWh/kgH2 [45] . Newer plant designs with higher efficiency could operate at a specific electricity demand of 6.8 kWh/kgH2 [45] [, but this still corresponds to about 20 % of the energy content of the hydrogen and thus adds considerable energy demand. For comparison, a compression of gaseous hydrogen to 500 bar for transportation or storage purposes requires ca. 2.4 kWh/kgH2 corresponding to 7% of the hydrogen energy content [40].

Due to hydrogen's low boiling point of 20 K, actively cooling liquid hydrogen is not feasible. In order to maintain the liquid state, therefore, insulating the storage tanks is essential. Such containers are a mature technology and have been used for many years, especially in the space sector [41]. However, completely preventing heat flow is not possible, so despite insulation, liquid hydrogen evaporates. The evaporated gas is discharged via a pressure relief valve to allow the tank to be operated almost without pressure, a process called "boil-off" [42]. As the size of the storage tank increases, the specific boil-off amount decreases due to a lower surface-to-volume ratio. While small tanks with a storage volume of 60 m^3 still lose about 0.4 % hydrogen per day, the boil-off rate at today's largest hydrogen storage facility, NASA's 3000 m^3 storage unit, is about 0.07 % per day. For future storage facilities in the range of 100,000 m^3, the boil-off rate might even drop to less than 0.01 % per day and would be almost negligible [43]. Additionally, in the case of large liquid storage facilities, it is feasible to harness the boil-off and store gaseous hydrogen in pressurized vessels, effectively removing the boil-off losses.

Hydrogen storage in pipelines

If an extensive pipeline network is developed for hydrogen transmission and distribution, a considerable volume of hydrogen would automatically be stored in that network. This has been the case for natural gas (NG) in the extensive pipeline systems for that fuel [8-10], although at a higher energy density than is possible for hydrogen. Comparing the energy (MJ) stored in the NG network [9] to the MJ that could be stored as hydrogen, the same volume NG stores 4 times the energy at 90 bar as would be stored in H2 at that pressure (Table 1). If the current US NG network consisted of all 36-inch pipes, it would store about 4% of annual NG usage. For the same annual usage, H2 would store about 1%. In the case of NG, 4% corresponds to usage for about 15 days, and for H2 (at the same use level), about 4 days. In both cases, static line pipe storage serves only short durations, for several days or less, since the gas is continually moving toward markets.

The total NG stored in the US is 1.3 billion m^3, or 4.7 trillion MJ. The size (volume) of H2 underground storage would have to be 3.6 times larger (4.7 billion m^3) to store the same MJ at 90 bar pressure. Hence if a similar amount of H2 were stored, it would require larger caverns for storage than natural gas.

However, a recent report by the Fuel Cell and Hydrogen Energy Association (FCHEA) and McKinsey modeling a future US Hydrogen Roadmap estimated 2050 H2 demand of about 90 million t/y for all uses including transportation, industry, and heating. Since one tonne of H2 has an energy content of 120 GJ, so the total 2050 demand for H2 was estimated to be 90 x 120 million GJ/y or 1.1 trillion MJ of H2 energy. This is about ¼ as much energy as the total energy storage in the US natural gas system. Thus in this example, the H2 storage needed would be similar to that for the current NG system [35].

Table 1: Comparison of the storage of natural gas (NG) and hydrogen (H2) in the US NG pipeline network

		Stored in 36 inch pipe $37.3 \times 10^3\ ft^3/mi$	Stored in 24 inch pipe $16.5 \times 10^3\ ft^3/mi$	Stored in 18 inch pipe $9.3 \times 10^3\ ft^3/mi$
Natural Gas (NG)	31 trillion MJ used in 2019 (1 TCf =1 MJ); 321,000 miles of pipelines			
	NG Stored in pipelines at 90 bar	25 billion kg 1.3 trillion MJ (4.2%)	11 billion kg 0.6 trillion MJ (1.9%)	6.3 billion kg 0.33 trillion MJ (1.1%)
Hydrogen (H2)	H2 stored in pipelines at 90 bar	2.6 billion kg 312 billion MJ (1%)	1.14 billion kg 137 billion MJ (0.44%)	.647 billion kg 78 billion MJ (0.25%)
H2/NG blend	15% H2/NG mix At 90 bar 15% by vol is 2.13% by weight	554 million kg H2 66.5 billion MJ H2 5.3% H2 energy		

The data in Table 1 indicate that the hydrogen stored in a pipeline network could function as daily storage for hydrogen. If the pressure of the system is increased, more hydrogen can be stored, a type of storage often referred to as line packing. There is considerable analysis in the literature of line packing with NG [11-14], but little considering line packing with hydrogen [15].

Line packing with hydrogen

Most of the references to H2 in pipelines are concerned with calculating flow and pressure drop in the pipes [16, 17] or potentially using or retrofitting NG pipelines for use with hydrogen [18, 19]. However, the analyses of line packing with NG [10-13] offer guidance for analysis with H2. The pressure in a pipeline will vary as gas is discharged from the pipeline and charged into it (Figure 4). The operator of the pipeline must control the discharge and charge functions to meet the demand of customers and the availability of NG. The pressure in the pipeline must be maintained within specified limits by material properties of the pipes and satisfactory operation of the system. The pipeline should be operated to maintain the pressure in the area between the pressure lines. The storage limit or line-pack flexibility is the mass of gas storage available to operate the pipeline. The line-pack flexibility can be estimated by calculating the mass of gas corresponding to the conditions in the pipe between the two pressure curves in Figure 4.

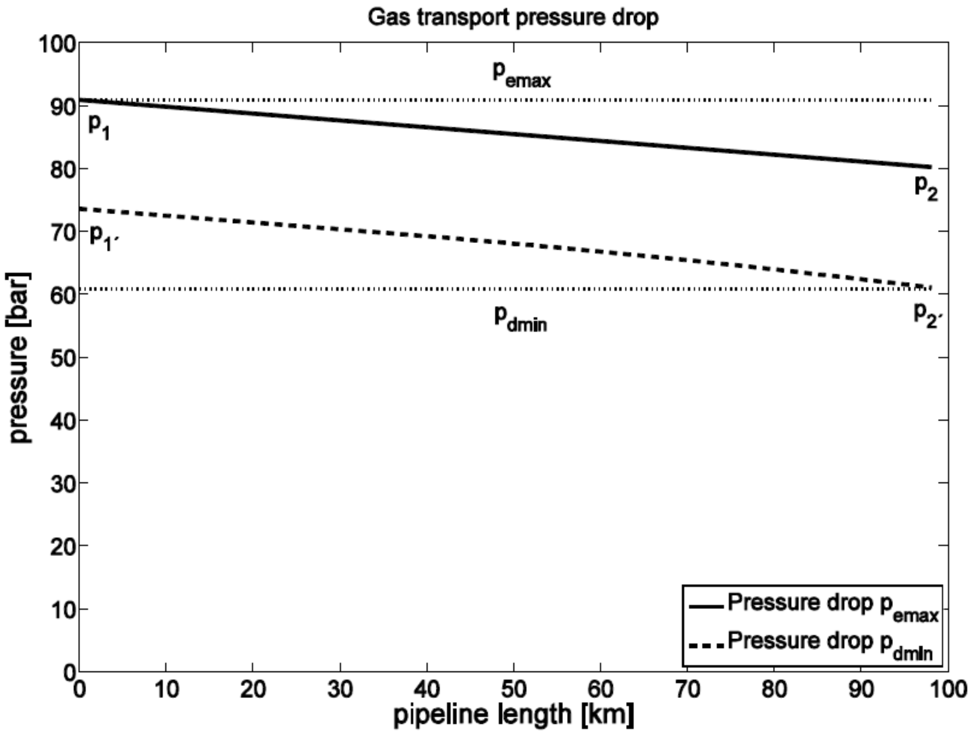


Figure 4: Line-pack flexibility in a pipeline [14]

The simple calculation of the kgH2 stored in the pipeline involves only the volume of the pipeline and the density of the hydrogen stored in the pipeline with consideration of the flow in the pipeline.

kgH2 stored = $\rho_{H2}\, Vol_{pipe,}$,, $\rho_{H2} = P\, MW_{H2} / ZR_0 T$, $Vol_{pipe} = (\pi D^2/4)\, L_{pipe}$

The primary effect of flow in the pipe is the pressure drop due to friction, which is given by

$$\Delta P = 1/2.\ \rho u^2 f\ L/D,$$

The above equation defines f, the friction coefficient for a pipe [20, 21]. As shown in Figure 5, f depends on the Reynolds number (Re= $u\rho D/\mu$) of the flow in the pipe and its roughness.

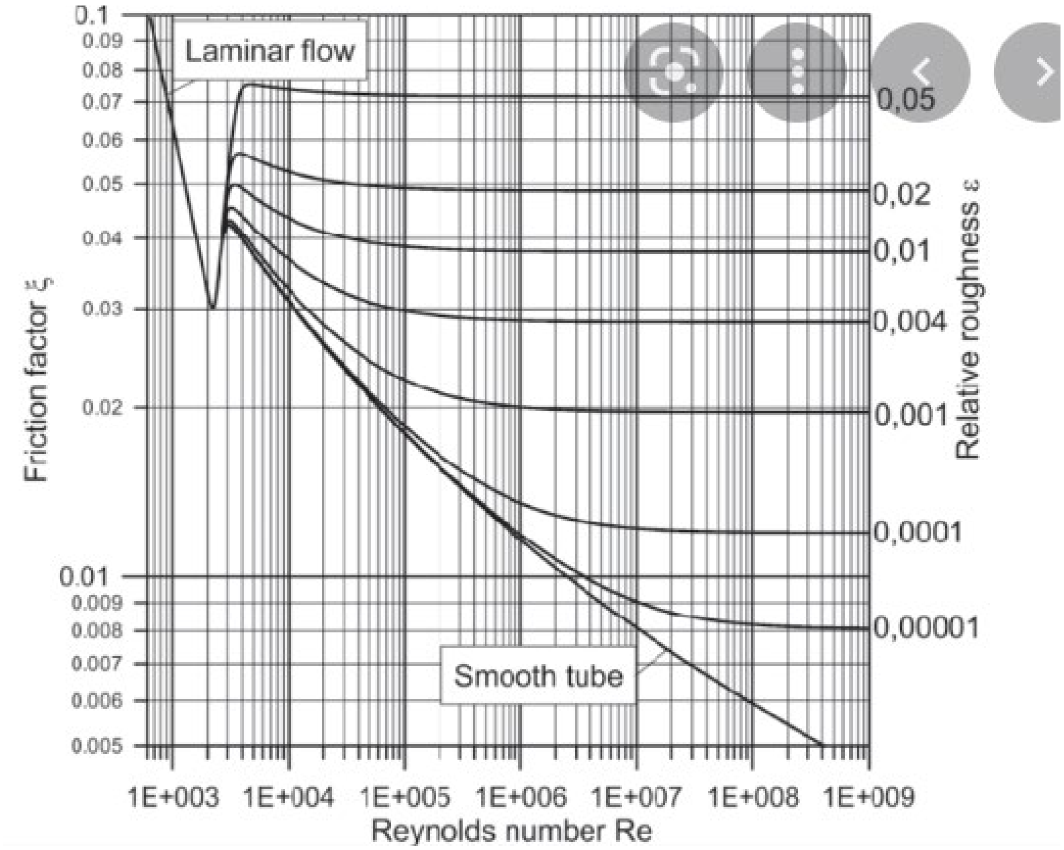


Figure 5: Friction coefficient for pipe flow [20]

The mass flow M(kg/sec) in the pipe is

$$M=u\rho A$$

Hence

$$P\, dP/dx = \tfrac{1}{2} (M^2/A^2)\, f/D\, (ZRT),\ R=R_0/gmMW_{H2}$$

Integrating, one obtains the equation for pressure drop in the pipe.

$$(1)\quad P_1^2-P_2^2 = CL,\ C=f\,(M^2/A^2D)\,(ZRT),\quad \rho_2/\rho_1 = P_1/P_2$$

The average pressure is given by

$$P_{aver} = 2/3\,(P_1^3-P_2^3/P_1^2-P_2^2)$$

The line-pack flexibility can be calculated using these equations.

Line packing calculations

We created a model to analyze the line packing of hydrogen in pipes of various diameter. This calculates the storage potential (kg/day) of the pipeline and the effective cost ($/kg) of utilizing the pipeline for H2 storage. It calculates the kgH2 stored in a specific length of pipeline during a flow of hydrogen from a specified initial pressure. However, those calculations do not estimate the kgH2 that can actually be used for storage. Any real storage situation must separately consider charging and discharging of the storage, as well as how long the hydrogen is held in storage. What is calculated in this analysis is the difference in the H2 mass in the pipeline flows from packed and unpacked initial conditions as a measure of the line packing potential of the hydrogen pipeline. The operator of the pipeline must continue to provide the H2 mass flow even during periods of packing.

In the present analysis, the packed pressure limit is 90 bar, and the unpacked pressure limit is 70 bar. The initial hydrogen flow was set to yield reasonable pressure drops in the pipe for the assumed friction coefficient of .025. The average densities in the flows were calculated using the average pressure P_{aver} assuming a constant temperature along the pipe. The section of the pipeline considered was between the compressor stations along the pipeline where hydrogen could be charged or discharged. The distance between compressor stations is customarily 50-100 miles. In this analysis, the pipe length between stations was taken to be 100 km. The results of the line-packing calculations are summarized in Table 2 for 48, 36, 24 and 12 inch diameter pipes. The pressure drop in a 36 inch pipe for 90 bar is shown in Figure 6. The maximum line-packing available per day was assumed to be the difference in the kgH2 in the 90 and 70 bar flow of the hydrogen in the 100 km pipe. The pipeline operator could vary the inlet pressure between 70 and 90 bar to control the H2 delivered to his customers. Figure 6 shows tradeoffs between pipeline diameter, pressure, and gas velocity in terms of pressure drop and the need to re-pressurize the pipeline at specific distance intervals. Small diameter pipelines, moving hydrogen at high pressure and high speed, have the greatest pressure drops.

The results indicate that line-packing in the larger pipes offers good opportunities for accommodating relatively large variations in daily hydrogen demand even if the hydrogen demand reaches 1.5 billion kg/yr (Table 1). The active pipelines needed for line-packing would only be 2000-4000 km. Line-packing cannot be utilized for long duration storage because it is necessary to keep the hydrogen moving through the pipeline network in order for customers to receive hydrogen and the pipeline operators to continue to receive revenue for their service. As shown previously in Table 1, large quantities of hydrogen could be statically stored in pipelines, but that quantity would be a small fraction of the total hydrogen demand. The projected cost ($/kgH2) of line-pack storage is low. For the larger pipe diameters, the cost is about $.05/kgH2 or less.

Table 2: Line-packing results for 70-90 bar for various size pipes, pipeline length 100 km

Pipeline packing situation		Pipe diameter, inches			
		48	36	24	12
Packed 90 bar	Outlet pressure (Bar)	81	78	72	47
	H2 flow (kg/da/km)	81.5k	48.2k	20.5k	4.3k
Unpacked, 70 bar	Outlet pressure (Bar)	63	61	56	37
	H2 flow (kg/da/km)	59.8k	33.1k	14.2k	38.5k
Line-packing 10% flow extracted 100 km pipe	KgH2 packing differential (kg/day)	277k	151k	62.5k	3.8k
	Fraction met* (kgH2/da/100km)	.067	.036	.025	.0014
	Total km pipeline CA*	1492	2777	4000	72k
	H2 cost ($/kgH2)	.015	.05	.057	.20

* assumes CA needs 1.5 billion kgH2/yr in 2040 for fuel cell vehicles

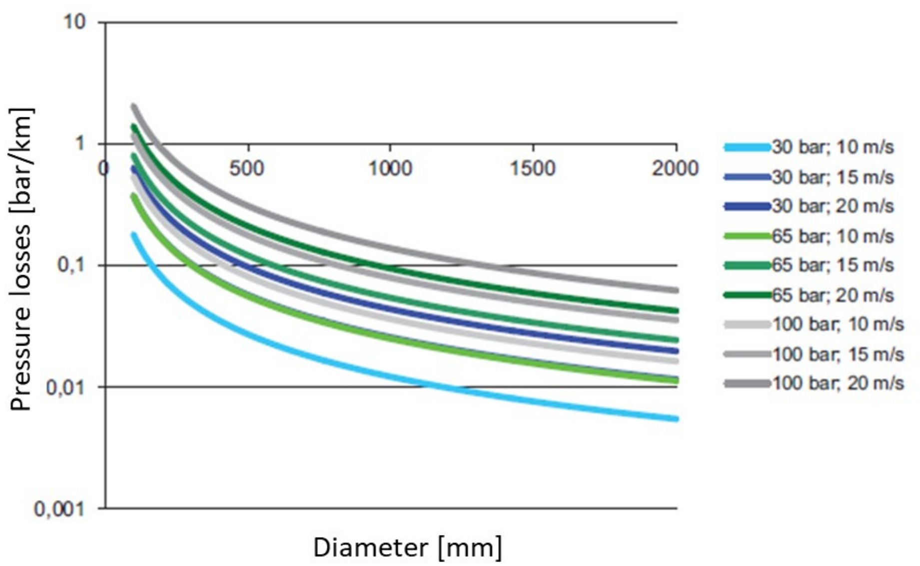


Figure 6: Pressure losses in relation to pipeline diameter, pressure, and gas velocity. Blue: 30 bar, green: 65 bar, gray: 100 bar [44]

Pipeline hydrogen transport

In many situations, hydrogen is transported over long distances to and from the underground storage sites before it is used. The cost of transporting the hydrogen will be considered in this section. There have been numerous reviews of pipeline costs [22-25] in the literature in which detailed calculations of converting NG pipelines for H2 and the building of new H2 pipelines are presented. Figure 7 shows the cost as a function of pipe diameter [22]. The costs are given in terms of the parameter $/meter/yr.

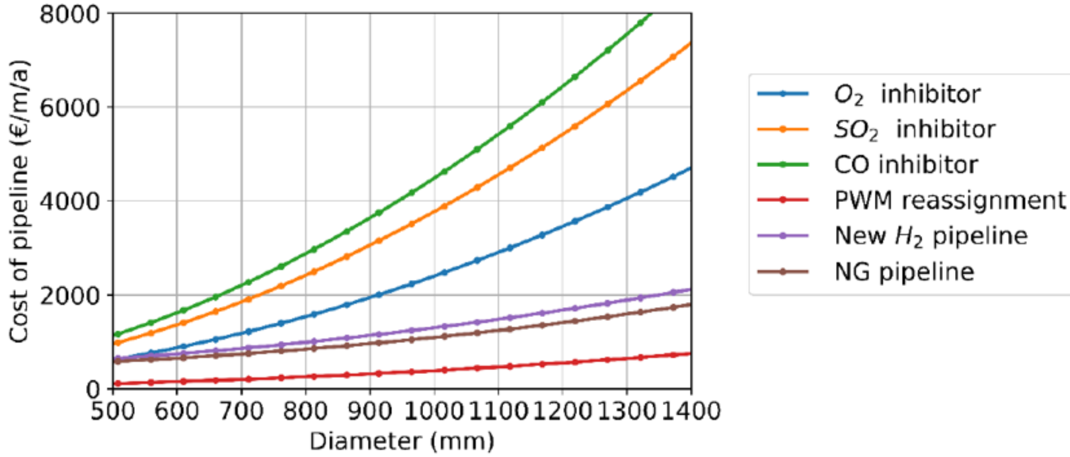


Figure 7: Levelized Cost comparisons of pipeline reassignment alternatives of inhibitors (O2,SO2, CO) and pipeline without modifications (PWM) and new H2 pipelines with natural gas (NG) pipeline [22]

In the case of new H2 pipelines, the parameter \$/meter/yr can be fit using the expression

$\$/\text{meter/yr} = 343-132\ (\text{dia}) + 889\ (\text{dia})^2$, dia in meters

The cost, which is the levelized cost per year, can be used to determine the cost of transport (\$/kgH2)

$\$/\text{kgH2} = (\$/\text{yr})/(\text{KgH2/yr})$, where $\text{KgH2/yr} = A_{pipe}\ V_{H2}\ \rho_{H2}\ 3600\ 24\ 365$, V m/sec , ρ kg/m^3

The hydrogen flow (kgH2/day) is dependent not only on the diameter of the pipe, but also on the pressure drop between compressor stations and the flow velocity (m/sec). The flow velocity varies with pressure and density in the pipe due to friction. It is convenient to use the density and flow velocity at the compressor station to calculate the mass flow through the pipe. The flow velocity V is calculated using Eq(1) of Sec 2.

$V_{H2}=((P_1^2/P_2 - P_2)*D)/(f*\rho_2*L_{comp}*1000)$, where L_{comp} is the distance between compressor stations

The transport costs of the pipeline were calculated for various combinations of pipeline design and pressure operating conditions. As indicated in Figure 8 and Table 3, the transport costs (\$/kgH2) vary over a wide range depending on pipe diameter, pipe length, and flow through the pipe. For all large diameter pipes, the cost is less than \$.5/kgH2, but for small diameter, relatively long pipelines, the cost can be high (> \$2/kgH2). Hence in assessing transport costs for pipelines, knowing the diameter and length of the pipeline is required.

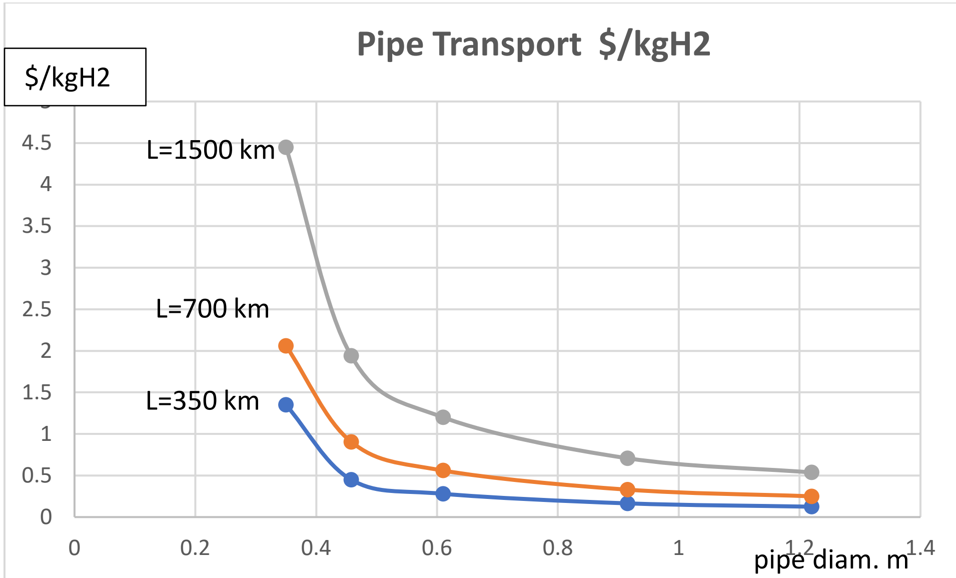


Figure 8: Transport cost ($/kgH2) of H2 in pipelines of various diameter and length

Table 3: Transport cost ($/kgH2) of H2 in pipelines

Pipe length km	100	200	350	700	1500	2500
Pipe diameter						
.305 m 12 inch	.29	.59	1.35	2.06	4.45	7.33
.458 18	.13	.26	.45	.905	1.94	3.23
.61 24	.08	.16	.28	.56	1.20	2.0
.915 36	.05	.09	.165	.33	.708	1.18
1.22 48			.125	.25	.537	.90

It is useful to compare the costs of transporting hydrogen by pipelines and truck. There have been several detailed analyses of the transport cost of hydrogen by truck as a compressed gas or as a cryogenic liquid [26-27]. Results from those studies are shown in Figure 9 and Table 4, and compared with our pipeline transport cost calculations in Table 3. In general (and for large pipes and volumes), the cost ($/kgH2) is significantly lower for transport in pipelines than in trailer-trucks even for distances of 100 km. The cost of H2 transport as a cryogenic liquid is close to that in pipelines for 12 inch diameter pipes, but for larger diameter pipes, the pipelines offer lower transport costs. Cost of transport of H2 as a high pressure gas by tube-trailer truck is high compared to pipelines for all diameters and distances. Much larger weights of H2 are transported as LH2 than as a compressed gas (4000 kg LH2 vs 600-800 kg 250 bar gas). The cost of transportation ($/kgH2) are much lower for LH2 as shown in Table 4.

Table 4: Comparisons of the levelized cost of H2 ($/kg H2) in pipelines and trucks [26, 27]

Distance km	Hi Press Gas Truck [26]	Hi Press Gas Truck [27]	Cryogen Liquid Truck [x]	Pipeline 12 inch	Pipeline 18 inch	Pipeline 24 inch	Pipeline 36 inch
100	1.4 160 km	1.1	0.4	0.29	0.13	0.08	.05
200	2.0 320 km	1.9	.6	.59	.26	.16	.09
350	2.6 480 km	2.9	.9	1.35	.45	.28	.165
700		4.9	1.25	2.06	.905	.56	.33

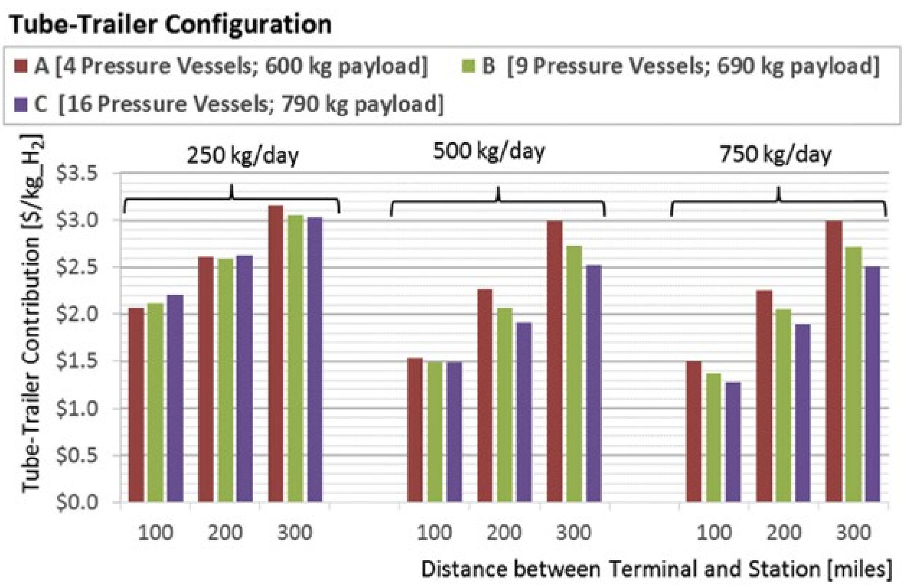


Figure 9: Costs of transporting hydrogen by truck as a high-pressure gas [26]

Table 5: Cost of transporting H2 in trucks [10]

	Truck cost ($k/unit)	Capacity (kg/unit)	Capital cost ($/kg)	Operating cost ($/kg/100 km)
Gas tube trailer—20 MPa				
Reddi (2016)	250	250	1000	
Petipas and Aceves (2018)	200–300	200	1000–1500	0.76
Chang (2007)—China	280	298	940	0.20–0.25
Gas tube trailer—optimized				
Reddi (2016)	626	800	783	
Composite—25 MPa (2018)	613–847	600–790	1020–1070	0.9–1.3
T4 54 MPa trailer (2018)	1300	1200	1080	0.26
Liquid trailer				
Reddi (2016)	718	4300	167	
Hydrogenics (2017)	1200	4000	300	0.10
Chang (2007)—China est.	370	4000	93	0.01–0.02

Long duration underground storage

There has been considerable experience and literature [8-10] on storing natural gas underground, but little for hydrogen. The data on storage of NG given above in Table 1 show that there is capability for storing underground about 15% of annual usage of NG. This is about 1.3 billion m^3 in which 3.7 trillion MJ of NG can be stored. In this same volume, 9 billion kgH2 (1 trillion MJ) could be stored at 90 bar. Most of the NG has been stored in depleted oil and gas reservoirs (see Figure 10). Hence there has been limited experience with salt and rock caverns with NG. On the other hand, there has been limited experience storing hydrogen in depleted oil and gas reservoirs, with salt caverns considered a more reliable storage type for hydrogen.

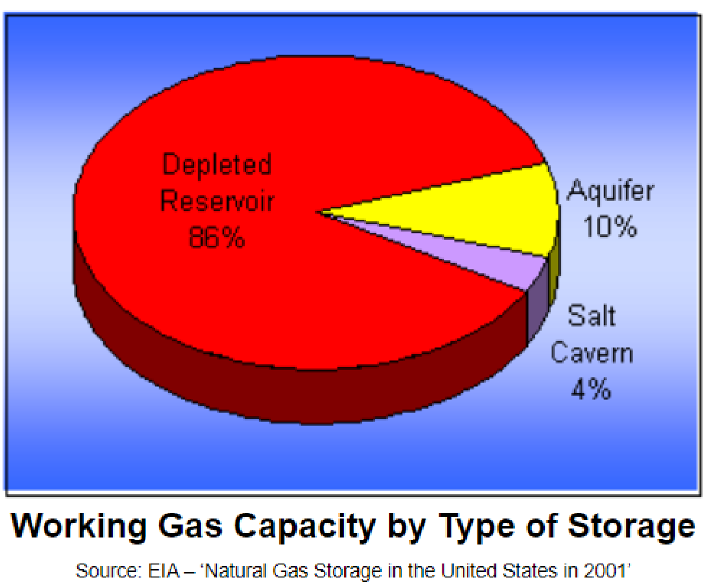


Figure 10: Working reservoirs for NG [8]

There are several strategies for underground storage of hydrogen, including salt caverns, depleted oil and gas wells, and hard rock caverns. As shown in the Table 6 [1], there are strengths and weaknesses for each type of storage, though salt caverns have the strongest set of positives overall. There are a few negative (minus sign) or neutral aspects (o) for oil or gas field storage, while salt caverns have inherent advantages in each of several key aspects, including investment and operation cost. Figure 11 from the EIA shows how underground storage is used for seasonal storage of natural gas. Underground storage could be used in a similar way for H2.

Table 6: Characteristics of various underground storage options for hydrogen [1]

	Salt caverns	Depleted oil fields	Depleted gas fields	Aquifers	Lined rock caverns	Unlined rock caverns
Safety	++	+	--	--	--	--
Technical feasibility	+	++	++	++	o	--
Investment costs	++	o	o	o	+	+
Operantion costs	++	--	o	+	++	+

Note: adapted by [1] from HyUnder (2013), Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Seasonal Storage of Renewable Electricity by Hydrogen Underground Storage in Europe: Benchmarking of Selected Storage Options.

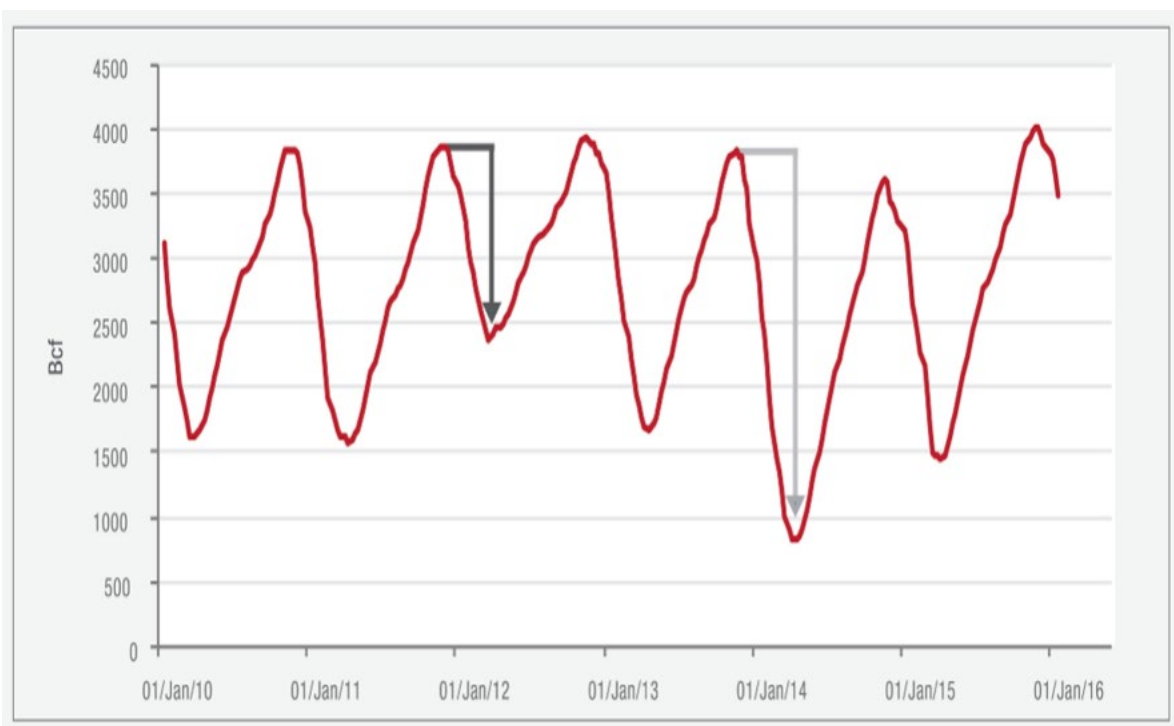


Figure 11: Natural gas working storage levels showing seasonal storage over several years [9]

Figures 12-14 provide a general sense of the distribution of potential geological storage sites throughout the United States. Salt deposits, which provide the lowest cost geological storage, are not particularly common in the Western US [2, 28, 29]. Figure 12 shows the size (billion ft^3) the various underground storage sites.

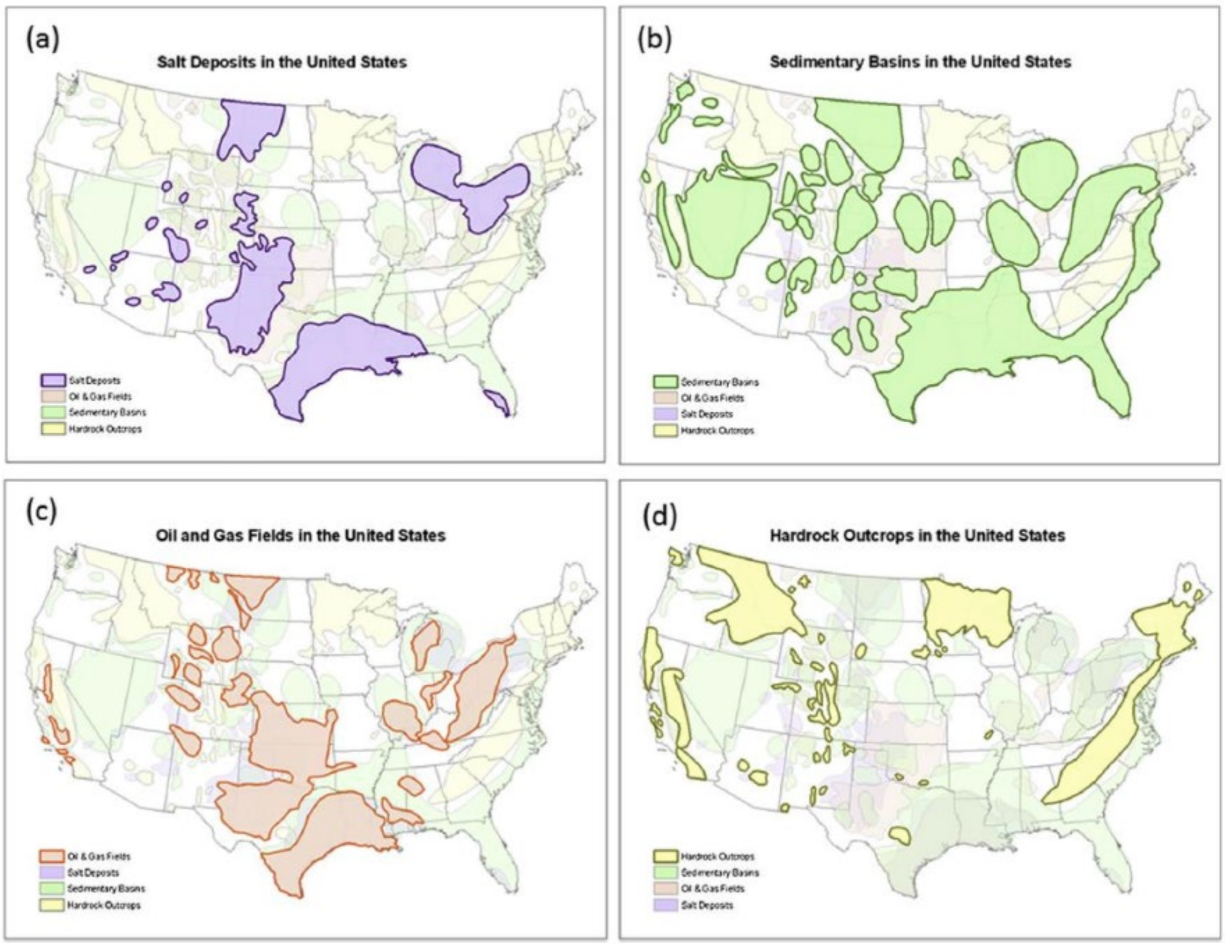


Figure 12: Locations of Underground storage sites in the United States [1, 28]

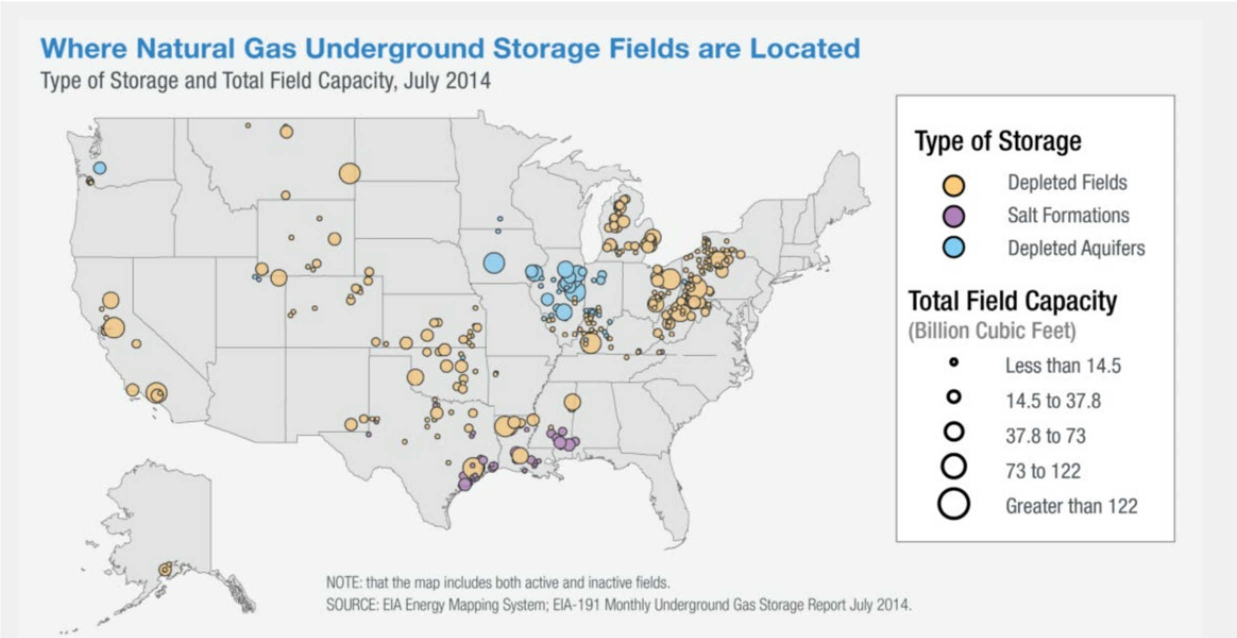


Figure 13: Field capacity (B ft^3) of natural gas storage sites in the United States [28]

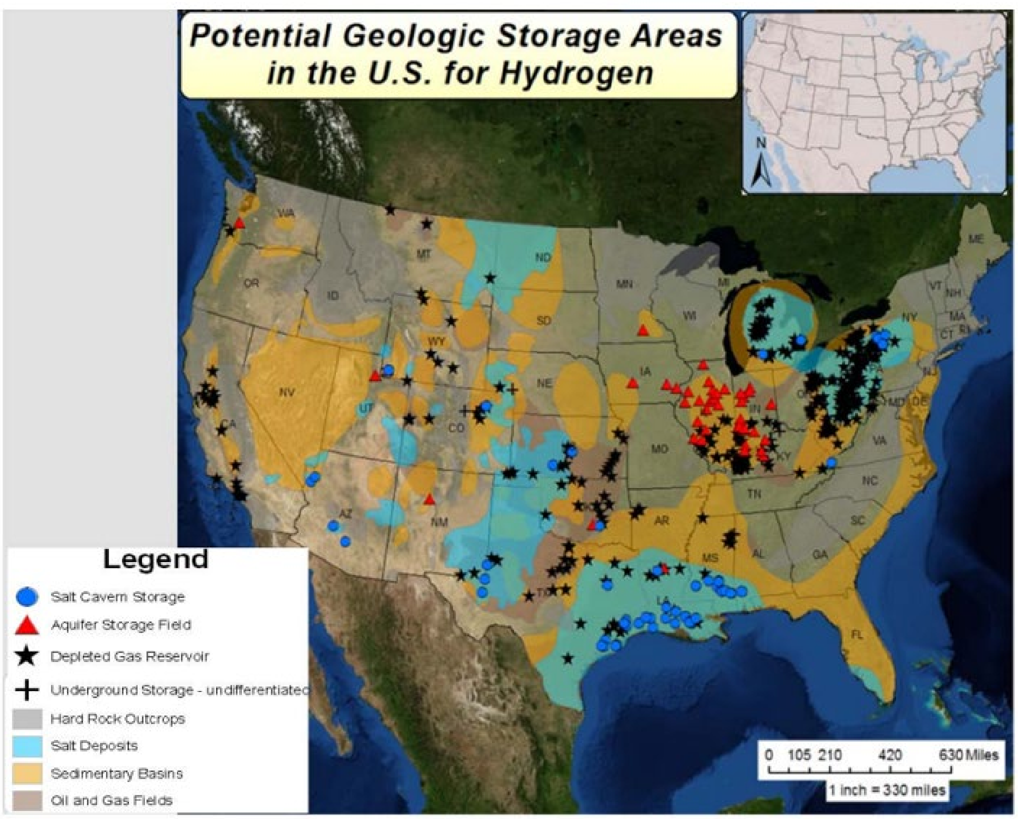
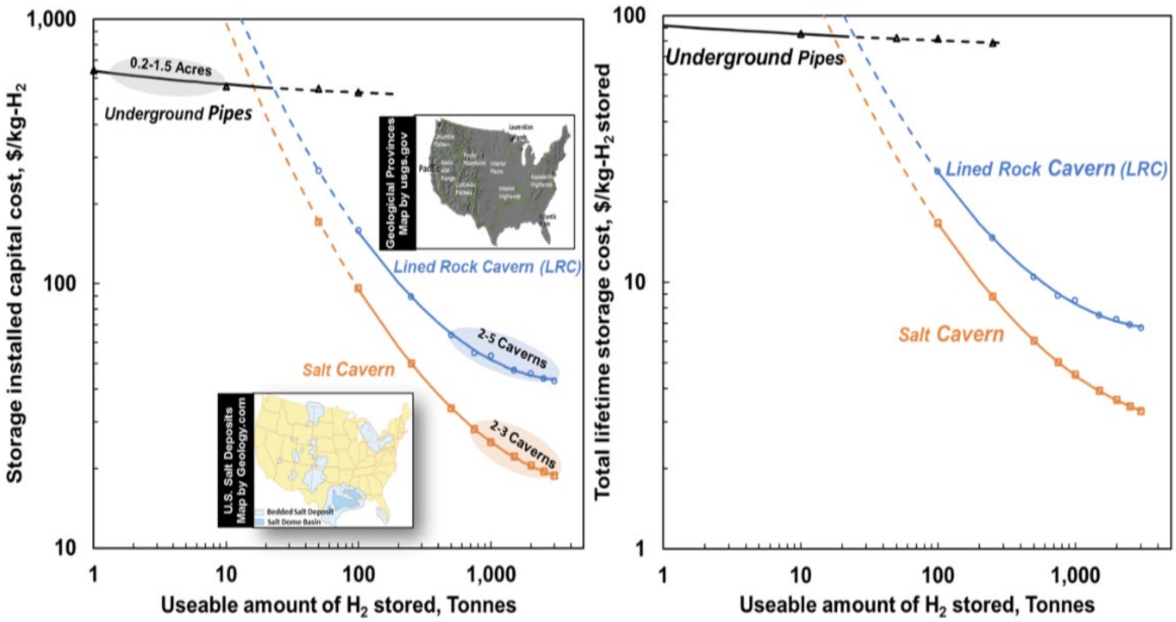


Figure 14: Detailed locations of underground storage for gases in the United States [29]

Figure 15 shows the capital cost per unit of hydrogen storage capacity and annual storage cost for salt caverns and lined rock caverns of different sizes [1, 2]. The storage costs are strongly dependent on the size of the storage (tonnesH2). The cost curves are still falling at 1000 tonnes and a capital cost of about $25/kgH2.



(a) Installed capital cost (b) Lifetime storage cost

Figure 15: Storage costs of salt and rock caverns [1, 2]

There have been several detailed projections of the cost of building cavern facilities for storing hydrogen [2,5, 29, 30]. One study's summary of the total capital cost of preparing various types of underground hydrogen storage is given in Figure 16 along with the resultant cost ($/kgH2) of the hydrogen. There are several contributors to the total cost which must be included in projecting the impact of the cost of storage on the dispensed cost of hydrogen, and these can vary significantly by type of geologic storage. Hard rock caverns are the most expensive to prepare, while depleted oil and gas reservoirs are the least expensive. Availability of any of these types of storage is always a key factor in choosing what type of storage to develop.

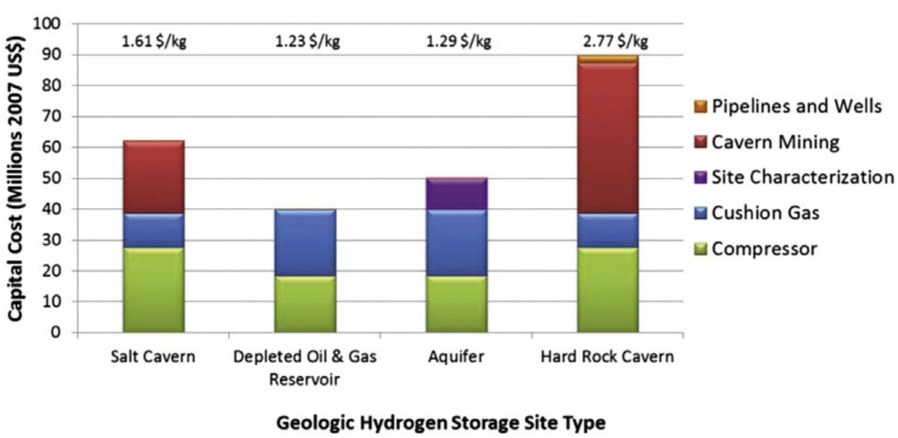


Figure 16: Projected cost of hydrogen for several underground storage options [29]

Detailed cost data for storing hydrogen in salt caverns of varying sizes is given in Table 7. This cost data is used in our cost estimates of H2 storage presented in the next section of this report.

Table 7: Breakdown of capital costs for deep cavern storage [2]

Cavern Roof Depth (ft)	1,500	2,000	2,500	3,000	3,500	4,000
Maximum storage pressure (atm)	70	100	120	140	170	190
Minimum storage pressure (atm)	22	29	35	41	47	53
Cavern water volume (m^3)	125,897	96,185	78,294	67,634	59,287	52,973
Cushion gas (%)	31.1	31.1	30.7	30.8	30.8	31.0
Drill+casing ($/kg)	$3.3	$4.4	$5.6	$6.7	$7.8	$8.9
Leaching ($/kg)	$5.1	$4.5	$4.1	$4.0	$3.8	$3.8
Mechanical integrity test ($/kg)	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3
Total construction costs	*$10.7*	*$11.2*	*$11.9*	*$12.9*	*$13.9*	*$15.0*
Geological survey ($/kg)	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3
Engineering ($/kg)	$1.6	$1.7	$1.8	$1.9	$2.1	$2.2
Contingency ($/kg)	$1.1	$1.1	$1.2	$1.3	$1.4	$1.5
Permitting ($/kg)	$0.3	$0.3	$0.4	$0.4	$0.4	$0.4
Total engineering costs ($/kg)	*$5.3*	*$5.4*	*$5.6*	*$5.9*	*$6.2*	*$6.5*
Brine transportation ($/kg)	$7.0	$5.3	$4.3	$3.7	$3.3	$2.9
Brine disposal ($/kg)	$7.0	$5.3	$4.3	$3.7	$3.3	$2.9
Total brine disposal costs ($/kg)	*$13.9*	*$10.6*	*$8.7*	*$7.5*	*$6.6*	*$5.9*
Compressor ($/kg)	$5.0	$5.7	$6.3	$6.9	$7.4	$7.8
Piping and instrumentation ($/kg)	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Cushion gas ($/kg)	$1.4	$1.4	$1.3	$1.3	$1.3	$1.3
Land cost ($/kg)	$0.8	$0.7	$0.7	$0.7	$0.7	$0.6
Total aboveground costs ($/kg)	*$8.1*	*$8.8*	*$9.4*	*$9.9*	*$10.4*	*$10.8*
Total cost ($/kg)	*$38.0*	*$36.0*	*$35.6*	*$36.2*	*$37.0*	*$38.1*

Modeling of underground hydrogen storage costs

As part of the present study of hydrogen storage, a model was prepared to analyze the cost of storing hydrogen underground in caverns and above ground in tanks. The above ground tank approach is suitable for short duration storage (up to several days) and the underground approach could be used for longer duration, seasonal (120-150 day) storage. The cost of the tank storage is often quoted as $400-600/kgH2, which is expensive compared to the low cost of underground storage. This could lead the reader to conclude that the tank storage contribution to the cost of hydrogen dispensed is high while the contribution to cost of underground storage is low. The analysis discussed in this section will show, however, that this is not usually the case.

The results yielded by any model depend on the inputs used to make the calculation. In the case of the underground hydrogen storage model, the key inputs and associated values are shown in Table 8 for typical cost calculations. The inputs values are based on those found in the literature [2, 5, 30].

Table 8: Input parameters for the underground storage model

Parameter	Ranges of values
Cavern size (tonnes	500-1000
Cavern capital cost ($/kgH2)	20-40
Storage pressure (bar)	150-200
Average hold time in storage (days)	15-150
Max fill rate (kg/h)	5000-10000
Compressor cost ($/kg/h)	200-400
Energy requirement (kWh/kgH2)	0.8-1.0
Electricity cost $/kWh	.05-.10
Capital cost recovery factor CFR	.08-.11

Model results for salt cavern storage are shown in Table 9 for a range of hold times. The hold time has a large effect on the contribution of storage to hydrogen cost ($/kgH2). In fact, for a few days of storage the cost of storage is less than $0.2/kgH2, and for several months the cost can be is more than $1/kgH2. In assigning a cost to seasonal storage, the effect of hold time must therefore be considered. The expected cost of seasonal storage will not be low for suitable hold times.

Table 9: Model results for underground H2 storage

Parameter	**Value**
Cavern size tonnes kg	500
Cavern cost $/kgH2	20
Storage pressure bar	150
Max fill rate	3 days
Compressor cost $ million	2.2k
Cavern cost $ million	10
Electricity cost $/kWh	.05
Average hold time days	**Levelized cost $/kgH2**
15	.235
30	.429
60	.815
120	1.59

Hydrogen storage at refueling stations

At refueling stations, hydrogen must be stored between deliveries and refueling events. The hydrogen can be stored either as a high pressure gas or as a cryogenic liquid (LH2). Storage as LH2 allows faster refueling and is more likely at large stations (>2000 kgH2/day). The physical characteristics and example capital cost estimates of storing hydrogen as a liquid and as a gas are shown in Table 10 and Figures 17-18. The LH2 is stored in highly insulated tanks that limit the boil-off to 0.5-1% per day [33]. The cost of LH2 storage is much lower than the storage of hydrogen as a high pressure gas (although the cost of liquefaction is substantial, not included here).

Table 10: Capital costs of hydrogen storage at refueling stations as a compressed gas and cryogenic liquid [33-34]

Hydrogen Phase	Temperature Deg K	Pressure atm	Density Kg/L	Capital cost $/kgH2 capacity
Compressed gas 1500 kg	300	350	.0235	~700 Steel with liner
Compressed gas 1500 kg	300	350	.0235	~650 Steel concrete composite
LH2- 3000 kg	15-20	5-10	.075	~70 Highly insulated
LH2-1000 kg	15-20	5-10	.075	~105 Highly insulated

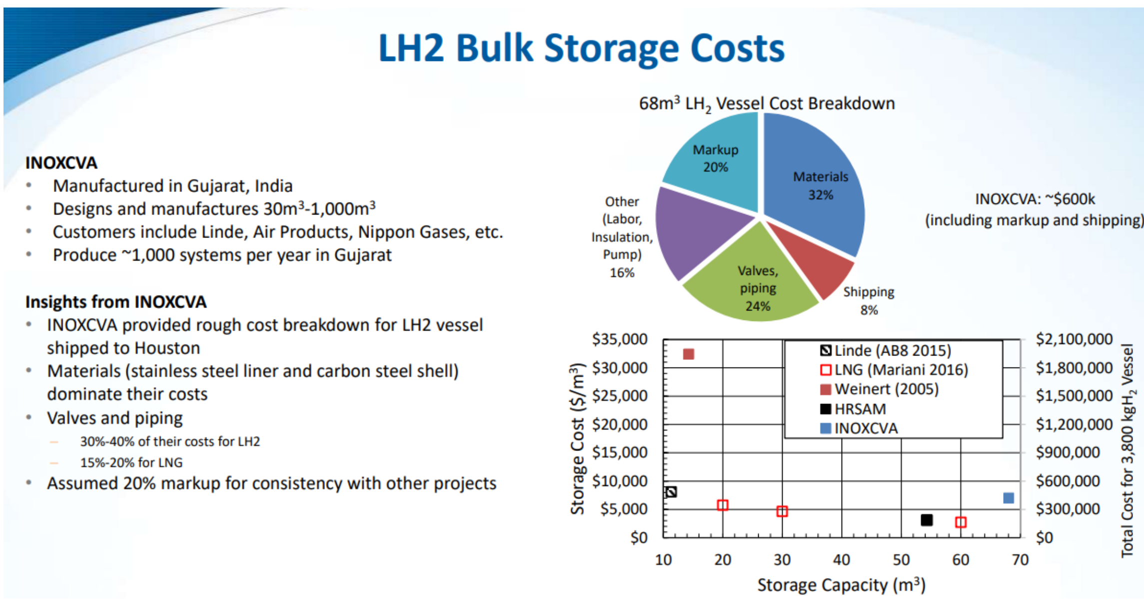


Figure 17: Capital costs of an example LH2 bulk storage system [33]

Analyzing the breakdown of expenses in these vessels reveals substantial allocations across various components [33]. In the case of INOXCVA's LH2 storage (Figure 17), the foremost expense pertains to material costs, predominantly constituted by Stainless Steel and Carbon Steel Shell, encompassing approximately 33% of the total expenditure. Nearly as significant are the costs attributed to valves and piping, comprising over 30% of the overall vessel expenses. Comparisons with alternative cited values, exhibit similar patterns in total cost allocation, with significant reductions from scaling of storage volume. These findings underscore the intricate balance of cost components within LH2 storage vessels, indicating potential variations influenced by differing materials, design paradigms, or operational requisites like scale.

Capital costs for a steel/concrete composite vessel are shown in Figure 18, for a situation with a 1500 kg storage tank, 6 foot diameter vessel. The charts show a) that the costs drop for higher pressurization levels, but also that over time, the expected costs have dropped, finally to a level below targets (based on US DOE targets as described in the paper). However as shown in Table 10, the associated costs per kg of hydrogen stored are likely to be relatively high compared to liquid storage.

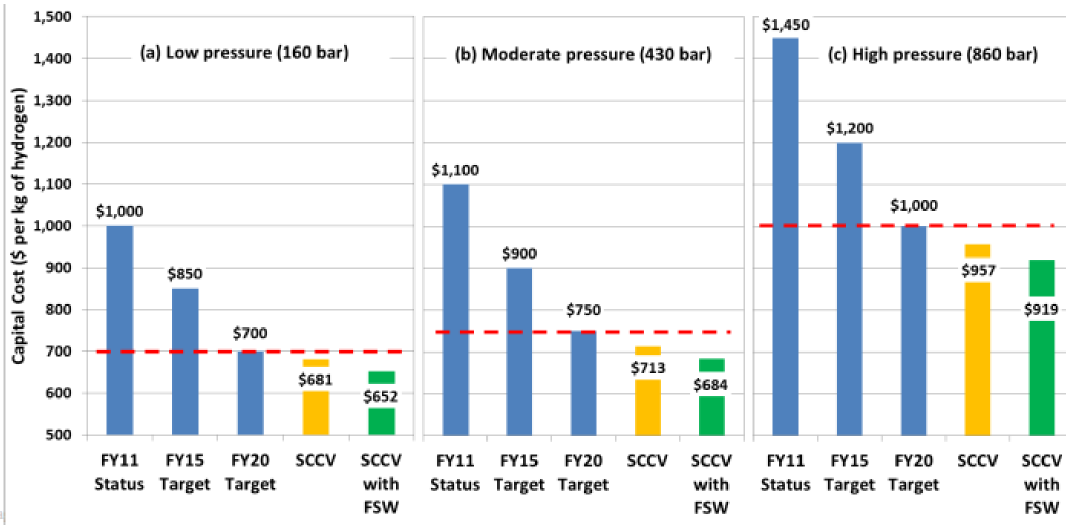


Figure 18: Cost of hydrogen storage by pressure level in steel/concrete composite vessels (SCCV) [34]

In a hydrogen refueling station of, for example, 1000 kgH2 per day capacity with high levels of utilization (e.g. refueling 150 cars per day at 6kg/car), the need to rapidly refuel successive cars requires high-pressure tank storage, typically around the size of the maximum daily utilization (1000kg for close to 100% utilization). We estimate the capital cost of a tank of that size at around $600/kg, for a $600,000 total cost. If this tank stores and dispenses the full 1000 kgH2 each day, and thus 365,000 over the course of a year, the annual levelized cost (with a capital recovery factor of 0.106) is 63,600. The levelized cost of the storage is thus $63,600/365000 kg = $0.16/kgH2. However if the utilization is only 50% (500kg per day on average), then the levelized cost of the storage would double to $0.32/kgH2. This is still a low cost of storage, though more than the cost of liquid storage on a daily basis.

Hydrogen storage cost as a function of duration

Hydrogen hold time and the total volume of hydrogen passed through the storage system are critical factors in determining the cost($/kgH2) of storage per unit in a particular situation. Each day hydrogen is stored, the net volume is constant but costs rise. This rising cost of storage with increasing hold times is illustrated in Figure 19, which also compares the costs of different storage options. As shown, for a single day all the options can be fairly low cost, with line packing being the most expensive, followed by pressurized storage. Liquid storage is slightly cheaper than salt cavern storage. However, even with just a few days of storage, salt caverns become cheapest, and pressurized storage the most expensive. Costs then tend to flatten (per kg stored) with longer storage times, but salt caverns are clearly the cheapest option if available.

Not all options, however, are available or practical in all situations. Due to their typically large volumes, salt caverns are generally supplied via hydrogen pipelines, with a minimum hydrogen storage of one week, in part since it takes up to 3 days to fill the cavern. Given the use of a pipeline, line packing is preferable for very short durations.

For intermediate periods, such as one week to one month, liquid hydrogen storage is likely to be cheaper than line packing. Liquid storage also has the advantage of being available for systems without pipelines, and is therefore more geographically flexible. High pressure storage is only cheaper than line packing for a very short (e.g. single day) duration, and is more expensive than liquid storage across all time frames.

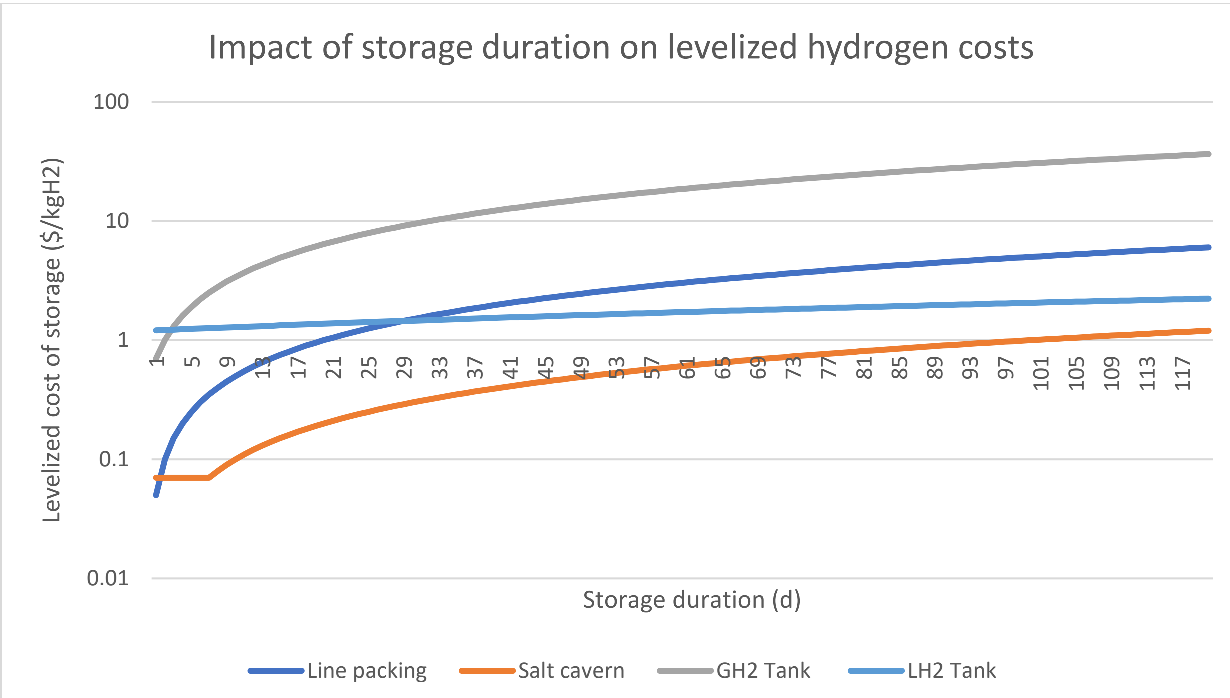


Figure 19: Impact of storage duration on levelized hydrogen costs (incl. compression and liquefaction costs; estimates generated by authors for this study).

Summary and conclusions

In this report, the literature and its estimates of technical and costs of various options for storing and transporting hydrogen were reviewed, with some original estimates also provided. The storage options considered were line-packing in pipelines, underground storage in salt caverns, liquid and high-pressure storage in tanks.

A key issue for cost is the duration of time that the hydrogen is held in storage before it is used. In the case of line-packing and high-pressure storage in a tank, the most cost-effective hold time is short, i.e. a day for high pressure storage or up to a week for line packing. Liquid storage can be cost effective for somewhat longer periods. Large volume storage in salt caverns can be cost effective for longer periods, i.e. many days or months, which is often referred to as seasonal storage.

The levelized cost ($/kgH2) of the storage for each option was calculated for a typical application. Our specific cost estimates can be summarized as follows.

- In the case of line packing in 36 and 48 inch diameter pipelines, the effective mass of hydrogen that could be stored for use in a day was found to be 150k-300k kg, and the cost was $.05/kg or less. This required the operator of the pipeline to vary the peak pressure to meet varying customer demand.
- The typical salt cavern case studied was for 500 tonnes of hydrogen storage. That cavern stored hydrogen at 150 bar and was projected to cost about $18M to prepare. The cost of storing the hydrogen in the cavern would be $1.6/kg, if it was stored for 120 days (4 months) and only $.24/kg if it was stored for only 15 days on a regular basis.
- Storing hydrogen at refueling stations for vehicles is done using high pressure tanks. At a 1000 kgH2/day station, the tank might store 1000 kg and cost $600,000. The hydrogen dispensers at the station would be connected to the tank, so all the hydrogen dispensed at the station would be fed through the tank. Hence the tank stored and could feed 1000 kg x 365 days of hydrogen to vehicles for refueling. The resultant cost would be about $.16/kgH2, with additional cost of 0.4 $/kg for compression.
- Alternatively, a LH2 storage for 14 days would cost 1.32 $/kg when liquefaction costs are included. This study indicates that the contribution of storage in applications requiring short, daily storage is low, and the cost of long duration, seasonal storage is much higher.

Regarding related hydrogen transport costs, the analysis showed significantly lower costs for transport in pipelines than in trailer-trucks, even for distances of 100 km. The cost of H2 transport as a cryogenic liquid is close to that in pipelines for 12 inch diameter pipes, but for larger diameter pipes, the pipelines offer much lower transport costs. Transport of H2 as a high-pressure gas by tube-trailer truck is high compared to pipelines for all diameters and distances.

Thus the costs of hydrogen delivered to stations is affected by both storage and transport costs, along with things like compression, liquefaction, and station costs associated with dispensing the hydrogen to vehicles. Production costs are also a major aspect of overall costs. This paper has focused on the storage cost of hydrogen with some related transportation cost detail; these estimates can then be added to estimates of other costs in the supply chain to derive a total cost per kg of hydrogen.

References

1. R., K., Ahluwalia, D.D. Papadias, J.K. Peng, and H.S. Roth, System Level analysis of Hydrogen Storage Options, U.S. DOE Hydrogen and Fuel Cell Program, 2019 Annual Review, Washington, D.C., May 2019

2. D. D. Papadias and R. K. Ahluwalia. Bulk Storage of Hydrogen**.** International Journal of Hydrogen Energy, Vol 46, Issue 70, 11 Oct 2021. Pages 34527-34541

3. IEA (2019), The Future of Hydrogen: Seizing today's opportunities, Report prepared by the IEA for the G20, Japan. International Energy Agency, OECD Paris. https://www.iea.org/reports/the-future-of-hydrogen

4. IEA (2015), Technology Roadmap: Hydrogen and Fuel Cells, International Energy Agency, OECD, Paris. https://www.iea.org/reports/technology-roadmap-hydrogen-and-fuel-cells
5.A S. Lord, P. H. Kobos, D.J. Borns, *Geologic Storage of Hydrogen: Scaling up to Meet City Transportation Demands,* Sandia National Laboratories, International Journal of Hydrogen Energy, 39 (2014) 15570-15582

6. M. Ruth, P. Jadun, N. Gilroy, E. Connelly, R. Boardman, A.J. Simon, A. Elgowainy, and J. Zuboy, 2020, The Technical and Economic Potential of the H2@Scale Concept within the United States. National Renewable Energy Laboratory. NREL/TP- 6A20-77610. https://www.nrel.gov/docs/fy21osti/77610.pdf
7. IRENA (2022), Global hydrogen Trade to meet the 1.5 deg C climate goal, Part II-Review of hydrogen carriers, International Renewable Energy Agency, Abu Dabi

8. http://naturalgas.org/naturalgas/storage/

9. Annual Report- Gas distribution, gas gathering, gas transmission, hazardous liquids, liquefied natural gas LNG), and underground storage of natural gas(UNGS), U.S. Dept. of Transportation, Pipeline and Hazardous Material Administration, https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

10. Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data, U.S. Dept. of Transportation, Pipeline and Hazardous Material Administration, https://www.phmsa.dot.gov/

11. Oil and Gas Journal, LP Model uses line-pack to optimize gas pipeline operation, internet, Feb 2003. https://www.ogj.com/pipelines-transportation/article/17240448/lp-model-uses-linepack-to-optimize-gas-pipeline-operation

12. Pipeline hydraulics (Line pack), APETT Engineering magazine, June 2018 Accessed July 2, 2018. https://www.apett.org/flipbook/#flipbook-apett-engineering-magazine-issue-5/7/

13. Power Magazine, March 1, 2022. Low-Cost Long-Duration Energy Storage at a Natural Gas Pipeline. Accessed Feb. 1, 2024. https://www.powermag.com/low-cost-long-duration-energy-storage-at-a-natural-gas-pipeline

14. Nico Keyaerts & Michelle Hallack & Jean-Michel Glachant & William D'haeseleer, 2010. "Gas Balancing Rules Must Take into Account the Trade-off between Offering Pipeline Transport and Pipeline Flexibility in Liberalized Gas Markets," RSCAS Working Papers 2010/71, European University Institute. Accessed Feb. 1, 2024. https://ideas.repec.org/p/rsc/rsceui/2010-71.html

15. D. Haeseldonckx and W. D'haeseleer, Concrete transition issues toward a fully-fledged use of hydrogen as an energy carrier: Methodolgy and modeling, International Journal of Hydrogen Energy, 36, (2011), 4636-465616. S. Kuczynski, M. Laciak, A. Olijnyk, A. Szurlej, and T. Wlodek, Thermodynamic and Technical Issues of Hydrogen and Methane-Hydrogen Mixtures Pipeline Transmission, Energies 2019, 12 (30, 569)

17. M.A. Khan, C. Young, and D.B. Layzell, The Techno-Economics of Hydrogen Pipelines, Transition Accelerator Technical Briefs Vol. 1, Issue 2, November 202118. V. Singh, R. Singh, A. Singh, and D.K. Mahaja, Tracking hydrogen embrittlement using short fatigue cracking dehavior of metals, Procedia structural integrity, 13 (2018), 1427-1432

19. L. Briottet, I. Moro, and P. Lemoine, Quantifying the hydrogen embrittlement of pipe steel for safety considerations, International Journal of Hydrogen Energy, Vol 37, issue 22, Nov 2012, 17616-17623

20. J. Mc Govern, Tech note: Friction factor diagrams for pipe flow, Technical University Dublin, 2011-11-10, jim.mcgovern@tudublin.ie

21. H.H. Bengtson, Pipe flow/ frictionfactor calculations using Excel spreadsheets, internet

22. S. Cerniauskas, A.J. Chavez, T. Grube, M. Robinius, and D. Stolten, Options of Natural Gas Pipeline Reassignment for Hydrogen: Assessment for Germany Case Study, International Journal of Hydrogen Energy 45(21), March 2020, International Journal of Hydrogen Energy 45(21), DOI: 10.1016/j.ijhydene.2020.02.12123

23. M.A. Khan, C. Young, and D.B. Layzell, The Techno-Economics of Hydrogen Pipelines, Transition Accelerator Technical Briefs Vol. 1, Issue 2, November 202124

24. P. Adam, F. Heunemann, C. von dem Bussche, Hydrogen infrastructure – the pillar of energy transition. The practical conversion of long-distance gas networks to hydrogen operation, Seimens Energy report, https://assets.siemens-energy.com/siemens/assets/api/uuid:3d4339dc-434e-4692-81a0-a55adbcaa92e/200915-whitepaper-h2-infrastructure-en.pdf

25. J.R. Fekete, J.W. Soward, and R.L. Amaro, Economic impact of applying high strength steels in hydrogen pipelines, International Journal of Hydrogen Energy, 40 (2015) 10547-10558

26. M. Reddi, A. Elgowainy, N. Rustagi, and E. Gupta, Techno-economic analysis of conventional and advanced high pressure tube trailer configurations for compressed hydrogen transportation and refueling, International Journal of Hydrogen Energy, 43 (2018), 4428-4438

27. M. Reub, P. Dimos, A. Leon, T. Grube, et al, Hydrogen Road Transport Analysis in the Energy System: A case study for Germany through 2050, Energies, 2021,14,3166

28. A.S. Lord, Overview of Geological storage of natural gas with emphasis on assessing the feasibility of storing hydrogen. Sandia report SAND 2009-5878

29. A.S. Lord, P.H. Kobos, G.T. Klise, and D.J. Borns, A lifecycle cost analysis framework for geological storage of hydrogen: a user's guide, Sandia Report SAND 2011-6221

30. DOE Technical targets for hydrogen delivery, https://guidehouseinsights.com/reports/hydrogen-transport-and-delivery; https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf

31. A.F. Burke and L. Fulton, 2022, Use of liquid hydrogen in heavy-duty vehicle applications: Station and vehicle technology and cost considerations, ITS-UCD Report, https://escholarship.org/uc/item/22z8260f.32. X. J. Li, J. Allen, J.A. Stager, and A.Y. Ku, Paths to low-cost hydrogen energy at scale for transportation applications in the USA and China via liquid-hydrogen distribution networks, Clean Energy, 2020, Vol. 4, No. 1, 26-47

33. Houchins, Cassidy and Brian D. James, June 2022, Hydrogen Storage Cost Analysis Project ID: ST235 Award No. DE-EE0009630 DOE Hydrogen Program 2022 Annual Merit Review and Peer Evaluation Meeting, https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/review22/st235_houchins_2022_p-pdf.pdf?Status=Master

34. Zhili Feng, (undated), Stationary High-Pressure Hydrogen Storage, Oak Ridge National Laboratory, https://www.energy.gov/eere/fuelcells/articles/stationary-high-pressure-hydrogen-storage

35. Fuel Cell and Hydrogen Energy Association (FCHEA). Road Map to a US Hydrogen Economy [Internet]. 2019 [cited 2020 Sep 5]. Available from: http://www.fchea.org/s/Road-Map-to-a-US-Hydrogen-Economy-Full-Report.pdf

36. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Hydrogen and Fuel Cells Technology Office, Hydrogen Tube Trailers, accessed on Feb. 1. 2024. https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers

37. Fulton, L.; Jenn, A.; Yang, C.; Burke, A.; Acharya, T.; Li, X., et al. (2023). California Hydrogen Analysis Project: The Future Role of Hydrogen in a Carbon-Neutral California: Final Synthesis Modeling Report. *UC Davis: Hydrogen Pathways Program*. Feb. 1, 2024. Accessed from https://escholarship.org/uc/item/27m7g841

38. Reuss, M. Techno-ökonomische Analyse alternativer Wasserstoffinfrastruktur, Energie & Umwelt /Energy & Environment Band/Volume 467 ISSN 1866-1793 ISBN 978-3-95806-414-0. Accessed Feb. 1, 2024. https://publications.rwth-aachen.de/record/765438/files/765438.pdf

39. M.R. Tahan, Recent Advances in Hydrogen Compressors for Use in Large-scale Renewable Energy Integration, International Journal of Hydrogen Energy, Vol. 47, Issue 83, Oct 2022, 35275-35292

40. DOE Hydrogen and Fuel Cells Program Record #: 9013 Date: July 7th, 2009. Title: Energy requirements for hydrogen gas compression and liquefaction as related to vehicle storage needs, Originator: Monterey Gardiner, Approved by: Sunita Satyapal, Date: October 26th, 2009. Accessed Feb 1, 2024.

41. Liquid Hydrogen Storage, Elsevier information page, accessed Feb. 1, 2024. https://www.sciencedirect.com/topics/engineering/liquid-hydrogen#:~:text=Hydrogen%20Storage,-

Balasubramanian%20Viswanathan%2C%20in&text=Liquid%20hydrogen%20has%20been%20used,in%20terms%20of%20storage%20pressure

42. R. Morales-Ospino, A. Celzard, V. Fierro, Strategies to recover and minimize boil-off losses during liquid hydrogen storage, Renewable and Sustainable Energy Reviews, Volume 182, 2023,113360, ISSN 1364-0321, https://doi.org/10.1016/j.rser.2023.113360.

43. WU Notardonato et al, 2017, Zero boil-off methods for large-scale liquid hydrogen tanks using integrated refrigeration and storage, *IOP Conf. Ser.: Mater. Sci. Eng.* **278.** https://iopscience.iop.org/article/10.1088/1757-899X/278/1/012012

44. D. Krieg, Konzept und Kosten eines Pipelinesystems zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff: Zugl.: Aachen, Techn. Hochsch., Diss., 2012. Jülich: Forschungszentrum Jülich, 2012.

45. Tietze, V., Luhr, S. and Stolten, D. (2016). Bulk Storage Vessels for Compressed and Liquid Hydrogen. In Hydrogen Science and Engineering: Materials, Processes, Systems and Technology (Eds. P.D.D. Stolten and D.B. Emonts). https://doi.org/10.1002/9783527674268.ch27