COMPARISON AND COST ANALYSIS OF PROMISING HYDROGEN STORAGE TECHNOLOGIES FOR LONG TERM ENERGY STORAGE

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Abstract

In the context of increasing penetration of renewable energy and the often inherently intermittent nature thereof, hydrogen could be an important cog in modern energy supply. Within a hydrogen power to power facility, the physical reservoir or carrier for storing hydrogen is an important consideration.

The paper compares the cost and technical implications of promising hydrogen storage technologies for application in South Africa for long term and large-scale use. This paper considers compressed hydrogen storage, liquid hydrogen storage and liquid organic hydrogen carriers.

The cost of liquid organic hydrogen carriers using integrated fuel cell heat was 2.36 R/ kWh$_{H2}$ and with electrical heat 4.83 R/kWh$_{H2}$, while salt cavern storage came in at 0.82 R/ kWh$_{H2}$ and above ground tank at 33.1 R/kWh$_{H2}$. Liquid hydrogen storage worked out to 2040 R/kWh$_{H2}$.

Keywords: Liquid Organic Hydrogen Carriers, Liquid Hydrogen, Compressed Hydrogen, Hydrogen Energy

1. Introduction

Energy storage is currently a garnering significant interest by researchers, government and industry alike. The intermittency of renewable energy and how to manage it is a constant topic of debate.

Requirements for discharge times among storage technologies differ, some discharge times are as short as a couple of milliseconds while others are as long as a couple weeks or even months. This makes each technology suitable for a certain application. Some applications include voltage and frequency control, renewable energy smoothing, load topping and seasonal storage[1].

Several energy storage technologies are in use today, each with its own characteristics and resulting applications. Technologies such as lithium-ion batteries are attractive for direct energy storage due to high round trip efficiency [2] and ease of implementation and scaling, but tend to be expensive and is not suitable for long term storage due to high self-discharge rates [3].

Thermal energy storage used in conjunction with concentrating solar power effectively slots into a time frame of hours to days [4] in terms of storage capacity, but does not go beyond that thus cannot compensate for seasonal changes.

Pumped hydro-electric storage is currently the most mature option for large scale seasonal storage. Despite this, the technology is severely limited by the need for appropriate geographical features and water resources and long lead times [5].

Hydrogen power-to-power (PTP), a mostly untested but promising technology, could potentially fill the gap of seasonal storage. Renewable energy-based hydrogen PTP usually consists of a electrolyser, a hydrogen storage system and a fuel cell [6].

In operation, this system uses surplus renewable energy to generate hydrogen via water electrolysis and then stores hydrogen for later use. In times of high electricity demand stored hydrogen can be used to generate electricity.

Of particular interest within this study is the storage of hydrogen within the PTP system. The storage of hydrogen is an important consideration within a hydrogen power to power system. Various storage technologies exist each with its own unique range of characteristics and costs.

This poses the question, what the technical and economic implications of the different hydrogen storage technologies are. This paper presents the comparison of different candidate hydrogen storage technologies for applications in South Africa.

The technologies considered are liquid organic hydrogen carriers (LOHCs), compressed hydrogen storage, liquid

hydrogen storage.

2. Hydrogen Storage

2.1. Compressed Hydrogen

Compressed hydrogen storage is probably the most mature and extensively used hydrogen storage technology. Simplicity and versatility characterise this technology resulting in widespread adoption across a variety of sectors, ranging from fuel tanks in hydrogen fuel cell vehicles to buffer storage at large industrial supply facilities.

In its most basic form, a compressed hydrogen storage facility consists of a compressor and a storage volume. The storage volume typically has a pressure ranging from 4 MPa [7] to 70 MPa [8]. The compression energy requirements depend on the maximum pressure of the storage volume and outlet pressure of the electrolyser.

Typically, systems for bulk hydrogen storage run at relatively low maximum pressures, often less than 20 MPa. For example the bulk storage at the Energiepark Mainz in Germany runs at maximum pressure of around 8 MPa [9] and the salt cavern hydrogen storage in Chevron-USA runs at no more than 13.5 MPa [10].

The choice of storage volume has a very large impact on the cost and versatility of compressed hydrogen. Generally, storage volumes can be divided into aboveground and underground systems which then can be further divided into a wide variety different types such as steel cylinders, composite tanks, or salt caverns.

Above ground gas storage is rather limited in its scale. Several bulk aboveground hydrogen tanks are in use today but are small in comparison to existing underground storage. The economics of large scale above ground CHS is questionable.

Some parallels can be drawn from large above ground compress air energy storage (CAES), which also requires large gas storage, albeit without the additional complications of hydrogen storage. In the CAES sector, two utility scale CAES facilities exist, both make use of salt caverns and not above ground storage [11]. Several start-ups focussing above ground CAES have struggled to successfully implement a viable system [12].

The bulk storage at Energiepark Mainz consists of above ground CHS of close to 1000 kg [9], which is small when compared to the nearly 3 million kg of hydrogen storage capacity of just one salt cavern at the Stublach natural gas storage facility[7].

A common feature among large gas storage facilities is the use of salt domes as the storage volume [13], [14]. For hydrogen it is particularly difficult to implement underground storage in non-salt caverns.

The general consensus in literature appears to be that in underground hydrogen storage significant bacterial activity can occur, especially in non-salt underground storage, but the overall effect of this requires more research [15]. What research does indicate is that several reactions can occur, such a reaction involving methanogenic bacteria which enables a reaction between carbon dioxide and hydrogen resulting in methane generation in the underground hydrogen storage and a reduction in hydrogen content [16], [17].

Thus, salt caverns are typically used for hydrogen storage to avoid complications of bacterial activity. The main benefits of salt caverns include their impervious nature and chemical inertness of rock salt [18].

The most common types of compressor is the reciprocating processor. Several other types of compressors exist such as ionic compressors, diaphragm compressors or even non-mechanical compressors such as adsorption compressors [19].

When emptying CHS it is important to maintain a certain minimum pressure. This minimum pressure means that some hydrogen, also known as cushion gas, will remain in the storage volume, effectively making it a capital expense [20].

Suitable rock salt deposits are required to implement compressed hydrogen in combination with salt caverns. According to a report on the structure of the salt industry in South Africa by the Department of Mineral Resources, there are no economical rock salt deposits for salt mining [21]. Very little other information regarding salt deposits is available.

While CHS is a simple and versatile technology, for large-scale applications a significant amount of pressurised storage is required. If salt caverns are not available then other options need to be considered, such as above ground storage. This may significantly increase cost of the storage facility.

2.2. Liquid Hydrogen

Storage and use of hydrogen in its liquid form has been around for quite some time and is a relatively mature technology with several large-scale liquefaction plants in operation today servicing industries such as semiconductor, metallurgical and chemical industries [22, p. 44]. LHS consists of a complex refrigeration cycle combined with very well insulated storage vessels.

The extremely low boiling point (-253℃) of hydrogen, second only to helium, results in a refrigeration cycle that is inherently energy intensive and technically complex.

To start the liquefaction process hydrogen is first compressed and then precooled with liquid nitrogen to -193 ℃. Expansion turbines then cool the hydrogen from -193 ℃ to -243 ℃. Finally, the hydrogen is from -243 ℃ to its boiling point -253 ℃, this step is accomplished using Joule Thomson valves [23].

Configuration and efficiency of liquefaction plant varies across industry. Several liquefaction plants, some in the range of tens of tonnes hydrogen production daily, are in operation [24].

Following liquefaction, cryogenic tanks store hydrogen until required. These tanks require near perfect thermal insulation to minimise losses[25]. Tanks are generally vacuum insulated.

Despite near perfect insulation, heat gain inevitable. This results in evaporation of some hydrogen over time. Periodic venting of LHS prevents hydrogen pressure build. This waste gas is also generally known as boil of gas [23].

Liquid hydrogen is not generally considered for long term hydrogen storage due to the inevitable hydrogen boil off that is present in most systems.

2.3. Liquid Organic Hydrogen Carriers

In the past decade a new hydrogen storage technology has caught the eye of researchers and industry alike, namely LOHCs. This promising technology has several advantages, such as high volumetric hydrogen density and safety, but what makes LOHC's unique is that they can be transported and handled under ambient conditions in a very similar way to diesel. LOHC dibenzyl toluene, for example, has a density of 1044 kg/m3 (diesel 850 kg/m3) and a relatively high flashpoint of 200 ℃ (diesel 52 ℃ or higher).

LOHC's are liquid hydrocarbons which have the ability to take up hydrogen by adsorption. Hydrogen is loaded onto the LOHC by exposing it to hydrogen under pressure. A commonly used substance, dibenzyl toluene, is already commercially available as a heat transfer fluid. Dibenzyl-toluene has a chemical composition of $C_{21}H_{20}$ with viscosity and colour similar to motor oil and remains stable in its loaded form (perhydro dibenzyl toluene with a composition of $C_{21}H_{38}$).

Typically, hydrogenation occurs at an elevated temperature and pressure. The elevated temperature in the hydrogenation process is due to the exothermic reaction between the hydrogen and the LOHC. Dehydrogenation requires the LOHC to be heated, often at ambient pressure.[26]. LOHC hydrogenation is an exothermic reaction while dehydrogenation is endothermic reaction with both being catalytic reactions[27].

LOHC dehydrogenation occurs at an elevated temperature which depends on LOHC substance. For example, commonly used LOHC, dibenzyl toluene, is dehydrogenated at a temperature of 270 ℃. The dehydrogenation heat required varies among different LOHCs and a lower dehydrogenation heat requirement is desirable [27].

Hydrogenation heat can be generated using electricity directly from the fuel cell, although this would be very inefficient. Better options are hydrogen combustion for heat generation or turbine, combustion engines or solid oxide fuel cells waste heat integration [28], [29].

Several LOHC's have been studied, some of the most common being dibenzyl-toluene, toluene and N-ethylcarbazole. Both toluene and dibenzyl-toluene are readily available in industry with toluene being produced in larger quantities [29] while N-ethyl carbazole supply is rather limited.

LOHC's inherent safety, ease of storage and zero self-discharge make it ideally suited for large scale storage. This allows it to be handled using existing infrastructure such as ships, ports and tanks [30].

3. Method

To compare the different technologies, the levelized cost of storage was used as a metric, adapted from the better known levelized cost of electricity metric [31], [32]. The formula is derived from the United States of America national renewable energy laboratories definition of levelized cost of electricity.

$$LCOS = \frac{CRF \times \text{capex} + \text{opex}}{E_a}$$

Where E_a is the annual energy output, capex is capital expenditure, opex is the operational expenditure and e_t is the energy consumption of the storage system. The capital recovery factor is

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1},$$

where t is period of analysis and i is a discount rate. The discount rate was assumed to be 7% and the period of analysis 20 years. While 7 % may be low for present South African conditions, it was chosen for this work to stay in a band of literature results for better initial comparison.

The extent of the analysis, as shown by dashed line in Figure 1, was limited to the storage reservoir of the hydrogen storage facility, this excludes hydrogen production and electricity generation.
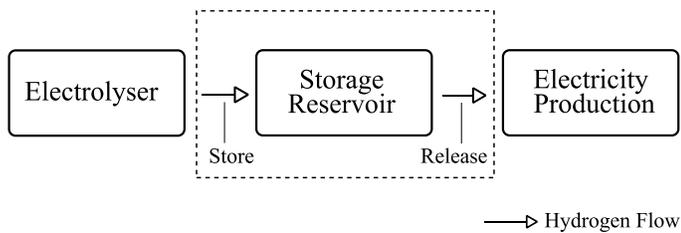
Figure 1. Extent of analysis within hydrogen PTP system

The capex and opex values were broken down into the main components for each technology. For these components various values were calculated using analogies or values from literature. Within the analysis, where necessary, values were adjusted for inflation. Where necessary, exchange rated of 15.56 ZAR/EUR, 13.62 ZAR/USD and 17.81 ZAR/GBP.

The cost of electricity was taken as 1.05 R/kWh used for calculating the cost of compression, liquefaction and other parasitic electricity uses.

The LCOS analysis was done in the context of a future renewable energy system where surplus renewable energy will be available to charge the energy storage systems for later use. A hypothetical system used in the analysis, the specifications were set at 500 MW discharge capacity with 31 days of storage and the capability to charge at a maximum rate of 250 MW. The system was assumed to be fully charged and discharged one a year.

3.1 Compressed Hydrogen

Two CHS scenarios were calculated, one for a salt cavern and one for above ground storage.

3.1.1. Capital Expenditure

Three different components were taken into account for the capital expenditure of CHS: cushion gas, compression cost and storage volume.

The cushion gas was assumed to be the cost of renewable hydrogen calculated in a recent study [33].

Various values were found in literature for compressor costs with varying degrees of reliability and suitability. Compressor cost was taken as 4808 R/kW_{H_2} as used by [34] since the value is fairly recent and is applied in a similar context as this study. While not exactly the same, the chosen value compares relatively well to other values used in literature [28][32].

For the salt cavern a value by [34] was used. The value is 4500 R/MWh_{H_2} or 149 R/kg of usable hydrogen storage in a cavern.

For tank storage, a value sourced from [35] was used. The tank can store 300 kg of hydrogen at a maximum pressure of 45 bar. The cost for one tank is 3 112 000 R or 10 400 R/kg. The tank

is intended for bulk storage at a hydrogen fuel station. This compares relatively well to the 8000 R/kg used by [36].

3.1.2 Operational Expenditure

Since detailed and reliable values for the cost of maintenance of large-scale hydrogen compressors were not found in literature, a different approach was taken. Instead a more general approach was used where annual maintenance was taken as a percentage of capital expenditure. For the purpose of this study the annual cost of maintenance was taken 4 % of compressor capex [34][37][38].

Energy consumption was taken as 0.0248 kWh_e/kWh_{H_2} for a 101 bar salt cavern [38].

For the above ground hydrogen tank maintenance, a percentage of 1.15 % of capex calculated using values given in [39].

As with the compressor, specific operation and maintenance costs were not readily available and thus 2 % of capital expenditure was taken as annual maintenance cost, as used by [40] for salt caverns.

3.3 Liquid Hydrogen Storage

3.3.1 Capital Expenditure

According to a very comprehensive project by the US Department of Energy [38], a 300 000 kg_{H_2}/day liquefaction plant would cost the equivalent of 760 000 R/kg/hour or 22 700 R/kW. This cost is the uninstalled cost of the liquefaction plant only.

A large 3500 m^3 liquid hydrogen tank costs the equivalent of 451 R/kg_{H_2} according to [38].

3.3.2 Operational Expenditure

A significant amount energy is required for liquefaction which was to at a rather conservative 12 kWh/kg as stated by [38].

According to [41] the boil-off losses for double walled, vacuum insulated spherical dewars are around 0.4 %, 0.2 % and 0.06 % per day for 50 m3, 100 m3 and 20 000 m3 tanks respectively. The decreased boil off with higher volume is expected due to the lower surface area per unit volume as the spherical container is increased in size.

A liquid hydrogen tank with a volume of 20 000 m3 could hold up to 1416 tonnes of hydrogen, which is approaching the desired size of the hypothetical storage used in this paper and thus a boil-off value of 0.06 % per day was assumed.

3.2 Liquid Organic Hydrogen Carriers

For the LOHC storage cost analysis, two dehydrogenation heat

scenarios were considered, i.e. waste heat from fuel cell and fuel cell powered electrical heat.

3.2.1 Capital Expenditure

For the hydrogenation plant [28] an analogy between a LOHC hydrogenation plant and the processes of diesel hydrodesulfurization and hydrodearomatization to estimate the capital expenditure required was used. Hydrodesulfurization is a process used to remove sulphur from hydrocarbons, such as diesel. The process as described by [42], is very similar to hydrogenation of a LOHC such as dibenzyl toluene. Therefore a value of 2418 R/kW was assumed for a large scale hydrogenation plants as used by [43].

Estimating the cost for storage tanks is rather simple since LOHCs can easily be stored at ambient conditions allowing for comparison with storage structures for crude oil or refined fuels.

For LOHC storage, figures from the 13.2-million-barrel crude oil blending and storage terminal which is in process of being finalised at Saldanha Bay [44] was used as an analogy. The facility will total R2.6 billion, which is equivalent to 1220 R/m³ and will consist of 12 in-ground concrete containers.

The LOHC was taken as a capital expense, the current cost of dibenzyl toluene is around 62.2 R/kg [28]. In a large scale plant economies of scale could bring down the cost of dibenzyl-toluene, to this end 40.6 R/kg was assumed as used in [43]. The maximum hydrogen loading level of dibenzyl-toluene was taken as 98 % [45].

[43] uses a value of 1298 R/kW for costing large scale LOHC dehydrogenation which is estimated from experience gained from the construction of a dehydrogenation facility at FAU Erlangen.

3.2.2 Operational Expenditure

Various factors influence the annual operational expenditure. These include prices of electricity and platinum, source of dehydrogenation heat and maintenance costs.

Consumption of the platinum catalysts needs to be taken into consideration. The catalyst was calculated to cost 1823 R/kg. Catalyst productivity for hydrogenation was assumed to be 500 000 kg of LOHC per kilogram of catalyst material [43]. For dehydrogenation the catalyst losses are assumed to be same as in the hydrogenation step.

In the hydrogenation step energy is also required for the compression of the hydrogen, which according to [28] is around 0.011 kWh_e/kWh_{H2}.

Maintenance cost of 12.1 R/m³ was adapted from cost of

maintenance of the Saldanha Bay concrete storage containers operated by the Strategic Fuel Fund [46].

Approximately 0.3 kWh_e/kWh_{H2} of heat is required in the dehydrogenation process [28]. In the case of electrical heat, the storage and dehydrogenation unit needs have an increased capacity.

4. Results

While the present study is ongoing in the sense that an expanding literature base and sensitivity studies feed into its data base, it is suggested that the data presented here already produces an indicative result. Thus, the most cost-effective storage technology was salt cavern compressed hydrogen storage at 0.82 R/kWh. Above-ground storage turned out to be a significant cost, pushing the cost of compressed hydrogen storage to 33.2 R/kWh.

Liquid hydrogen storage turned out to be the most expensive storage technology by far. At 2040 R/kWh liquid hydrogen storage exceeds the cost of salt cavern storage by 4 order of magnitudes. The reason for this was the substantial capital costs. Both the storage tank and liquefaction plant turned out to be very expensive.

LOHC occupied the middle ground in terms of cost, although the use of electrical heat nearly doubled the cost. But was still less expensive than above-ground compressed hydrogen storage.

Table 1 summarises the various LCOS results for different scenarios were calculated.

Technology	Configuration	LCOS
Compressed Hydrogen Storage	Salt Cavern	0.82
	Above-Ground Tank	33.1
Liquid Hydrogen Storage	-	2040
LOHCs	Integrated Heat Fuel Cell	2.36
	Electrical Heat	4.83

Table 1. Summary of results of LCOS analysis in R/kWh$_{H2}$

5. Discussion

Despite the low cost, compressed hydrogen storage in Salt caverns application is severely restricted by the limited availability of salt caverns. The lack of known and appropriate salt deposits in South Africa limit the technologies local application. Above-ground compressed hydrogen storage is

also problematic, it is 40 times more expensive than salt cavern compressed hydrogen storage. Interestingly, even with a 50% reduction in costs of the above-ground storage vessels above ground compressed hydrogen is not cost competitive with salt cavern storage.

The high cost of liquid hydrogen was expected and is a result of the combination a complex liquefaction process, heavily insulated storage vessels, inevitable boil-off and high energy consumption.

While LOHC storage is more expensive than salt cavern compressed hydrogen storage, it does not require special geology. This allows LOHC storage to implemented practically anywhere and has the additional benefit of no pressurised or cryocooled storage components.

Integration of cost-effective dehydrogenation heat is essential for cost effective and efficient LOHC storage. This necessitates a high temperature fuel cell or turbine heat or other waste heat. Unlike proton exchange membrane or alkaline electrolysers, high temperature fuel cells such as solid oxide fuel cells are not very mature technologies and still have many technical limitations.

6. Conclusions

Hydrogen PTP is a promising but not yet mature technology for energy storage and its role within energy provision section not yet certain. Hydrogen PTP still has several limitations and questions which need to be resolved. The purpose of the research in this paper lies in the development attempts to answer the question of hydrogen storage for long-term large-scale use with a cost analysis tool which will be refined going forward and which can be used to examine the economic implications of hydrogen storage technology as it develops.

The analysis considered only the storage of hydrogen part of a PTP system, excluding components such as electrolysers and fuel cells. Included were components that are needed to store hydrogen in and/or release hydrogen from hydrogen medium. The analysis compared the levelized cost of storage of different scenarios of compressed hydrogen, liquid hydrogen and LOHCs.

The analysis showed that liquid hydrogen significantly is by far the most expensive, followed by above-ground compressed hydrogen storage, LOHCs. The least expensive technology by far was compressed hydrogen storage.

Should the production of hydrogen become viable on a large scale for a renewable energy system would likely open significant markets for electrolysis (wind, PV) or high temperature processes (CSP/CST).

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