

Master's Programme in Innovative Sustainable Energy Engineering

Techno-economic Pricing model for Carbon Neutral Fuels for Seasonal Energy Storage

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Abstract

Green hydrogen produced through electrolysis of excess renewable energy is a promising seasonal energy storage solution with the potential to decarbonize the energy sector. However, it has physical properties that make it difficult to store and transport on a large scale for grid scale storage applications. An alternative to storing excess renewable energy in hydrogen is converting the hydrogen to synthetic fuel that has an industrially mature production process and an established transportation, storage and distribution infrastructure. This study aims to conduct a feasibility analysis to compare the cost and compatibility of green hydrogen, ammonia, methane and methanol as seasonal energy storage. The production of each fuel and the barriers to their commercialization as energy vectors is discussed. The hydrogen storage technologies holding the most potential are identified as salt cavern and lined rock cavern storage however type I-IV pressure vessel storage is also included in the analysis due to its prevalence within the industry

The outcome of the study is a conceptual model calculating the levelized cost of storage of each fuel considering the storage system size, compression energy required and annualized CAPEX and OPEX of compression and storage. Three cases are developed to analyse the storage system, A- seasonal discharging, B-weekly discharging and C- daily discharging. The results identify that the most feasible seasonal storage option for hydrogen is utilizing a salt cavern. If building a salt cavern is infeasible due to geographical constraints, a lined rock cavern is more cost-effective as compared to utilizing pressure vessel storage. For shorter storage periods or smaller scale applications it is more beneficial to employ low pressure (200-300 bar) pressure vessel storage since geological storage becomes expensive as compared to the seasonal case. Low pressure storage is better suited for smaller applications as compression costs account for a significant share of the total annual cost of each storage system in the weekly and daily cases. The most suitable hydrogen storage option is highly dependent on the end use application. Overall, methanol storage provided the lowest levelized cost of storage in all scenarios.

Keywords Hydrogen, seasonal storage, geological storage, carbon-neutral fuels

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Ananya Saraf
Student

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List of Abbreviations

RES	Renewable Energy Sources
LTES	Long Term Energy Storage
HYBRIT	Hydrogen Breakthrough Ironmaking Technology
BES	Battery Energy Storage
PtG	Power-to-gas
PtL	Power-to-liquid
SNG	Synthetic Natural Gas
PtM	Power to Methanol
PtA	Power to Ammonia
H-B	Haber-Bosch
CGH ₂	Compressed Gaseous Hydrogen
LH ₂	Liquified Hydrogen
UGS	Underground Gas Storage
UHS	Underground Hydrogen Storage

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1. Introduction

According to the Paris Agreement, limiting global warming to 1.5°C is pivotal in order to prevent the irreversible and deleterious consequences of climate change. One of the most vital climate change mitigation strategies is to salvage a rapidly depleting global carbon budget and to advance towards decarbonizing all sectors. In particular, the power sector, which contributed to 40% of energy related emissions and 25% of global greenhouse gas (GHG) emissions in 2017 [1]. Although the share of renewable energy generation is increasing rapidly, taking the example of the EU, where renewable generation (38%) surpassed fossil fuel generation (37%) for the first time in 2019, a significant uphill battle remains for achieving a 100% carbon neutral energy system [2].

Given the intermittent nature of renewable energy sources (RES) such as solar and wind energy and the increasing electrification of the mobility, heating and industry sectors, achieving high RES capacity requires in a broad sense; (i) increased energy efficiency measures on both the demand and supply side, (ii) negative emissions technology to abate the expected emissions from future RES development e.g., biomass carbon capture and storage, (iii) flexible dispatchable power generation for balancing needs and quick ramping, (iv) increased grid interconnection capacity and finally, (v) energy storage (ES) that meets residual load and provides short term and long-term flexibility. The combination of solutions that will be implemented depends on specific regional and policy drivers however the need for long-term energy storage (LTES) is irrefutable.

In a comprehensive literature review conducted on the energy storage requirements to achieve an entirely renewable power sector, it is estimated that to achieve 95% RES globally a storage size in the order of 600 TWh is required [3]. This is approximately equal to 1.5% of current global demand. On a country level scale, a study conducted in Germany forecasted the storage demand would be in the range of 20-45 TWh for the nation to reach 100% RES [4]. Thus, it is also incontestable that systems with high renewable energy require not only a long-term but also a large (TWh) scale storage solution.

Seasonal storage has been identified as an effective large-scale LTES that stores surplus electricity generation caused by weather patterns and temperature differences i.e., high wind speeds during winter and higher levels of solar irradiation during summer. It also ensures grid resilience by maintaining sufficient long-term energy reserves in cases of emergency (unexpected) events such as climate disasters or demand spikes [5].

In general, seasonal storage solutions must have certain requirements [5]:

- Energy is required to be stored with a low self-discharge rate
- Large scale to meet unexpected load swings
- High cycle efficiency to prevent wasted energy

- Low costs per MWh

These factors govern the feasibility of seasonal storage and its ability to be integrated into a specific energy system. In order to assess which storage technology would be most suitable, it is important to consider the trade-offs that arise within these requirements e.g. a technology that has low costs per MWh might have a low cycle efficiency. Technologies should be assessed in a balanced and holistic manner.

Green hydrogen produced through electrolysis of excess renewable energy is a promising seasonal energy storage solution because it is a clean, carbon neutral fuel with the potential to decarbonize the energy sector and hard to abate sectors such as transport and industry [6]–[8]. Hydrogen can also be injected into the gas grid and used as a carbon-free reducing agent for steel production, called the Hydrogen Breakthrough Ironmaking Technology (HYBRIT). Dubbed as the ‘new oil’, demand for the light, abundant gas has grown from 18.2 Mt in 1975 to 73.9 Mt in 2018, the bulk of which is utilized in oil refining (52%) and ammonia production (42%) [9], [10]. Figure 1 shows the increase in hydrogen demand globally and the end-use sectors which contribute to the demand.

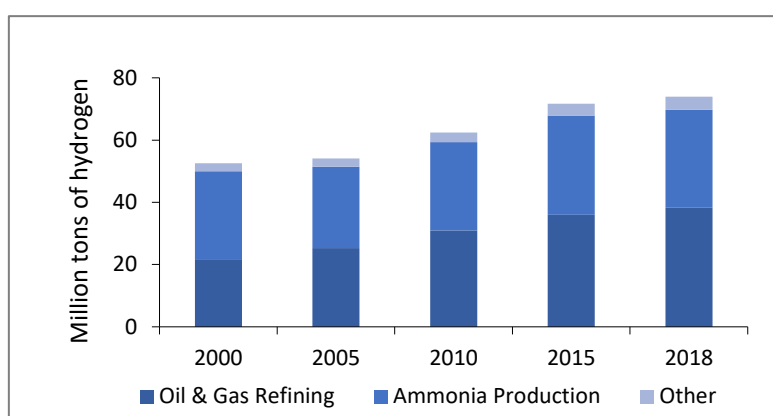


Figure 1: Hydrogen demand from 2000 - 2018 by end-use sector. 'Other' represents demand for processes that require hydrogen in small quantities in gas mixtures, fuel or feedstock – Source: International Energy Agency (IEA)

The premise behind utilizing green hydrogen as a form of seasonal storage is the expected increase in RES within energy systems leading to the dearth of low cost, large scale dispatchable generation. Studies assessing the feasibility of different ES technologies to meet this need have concluded that green hydrogen is a competitive form of seasonal storage due to its low energy capital costs and high gravimetric energy density (120 MJ/kg), close to three times that of methane (50 MJ/kg) [11]–[13].

However, it has physical properties that make it difficult to store and transport on a large scale for grid-scale ES applications. It has a relatively low molecular weight, low boiling point and most importantly, low volumetric density (0.089 g/L) at standard temperature and pressure conditions (STP). This makes it more prone to leakages and means it requires more energy for compression and liquefaction making the gas very difficult to store within conventional gas storage without substantial modifications.

Moreover, transporting large volumes of hydrogen within the current gas grid infrastructure is currently not feasible. It is possible to inject hydrogen into natural gas pipelines however, the blending mandates of hydrogen within natural gas pipelines are quite low with the highest being 10%- by volume in Germany and 6%-by volume in France, when considering EU member states [14]. This is because hydrogen's combustion characteristics greatly differ from those of natural gas and there is an increased risk of leakages as a result of hydrogen embrittlement (propagation of cracks in the steel piping infrastructure caused by hydrogen's reactivity and exacerbated by high pressure).

Pressure fluctuations as a result of intermittent hydrogen production will aggravate this problem and studies have shown when different loading conditions are modelled on a conventional X60 steel pipe, crack propagation increases by a factor of 2.7 [15]. There are also logistical concerns regarding maintaining hydrogen concentration at the feed-in point and the different concentrations that can be burned in internal combustion engines, gas turbines or in heat only boilers or steam turbines for district heating.

Until a global 'hydrogen economy' with a mature hydrogen supply chain is conceivable, an alternative to storing excess renewable energy in hydrogen is converting the hydrogen to synthetic fuel that has an industrially mature production process and an established transportation, storage and distribution infrastructure. The main synthetic fuels which are being assessed as secondary energy carriers are methane, methanol and ammonia, all of which are commonly employed by the energy and industrial sectors.

This thesis develops a levelized cost of storage (LCOS) model to compare the cost of green hydrogen, ammonia, methane and methanol as seasonal energy storage. The choice of the most suitable hydrogen storage for large scale storage is also analysed depending on operational characteristics prior to the cost analysis.

1.1. Recent research on hydrogen energy storage

Utilizing hydrogen for large scale and long-term energy storage applications is not a new concept in the energy sector however, it is industrially nascent. Hydrogen storage that are currently available in the market are more focused towards storage for mobility due to the uptake of fuel cell electric vehicles (FCEVs), one of the main technologies seen to lead decarbonization of the transport sector.

The main challenge for storage of hydrogen for FCEVs is ensuring ample on-board storage capacity for average vehicle traveling distances e.g. 300-500 km without the need to refuel. Thus, the ideal form of energy storage would have a high volumetric and gravimetric density, provide quick release of hydrogen within a specific temperature interval (for enabling heat integration with fuel cells), have a low risk of leakage and finally be cost effective [16]–[18]. Several studies have analysed various hydrogen storage technologies for this application and identified that compressed gas storage (350-700 bar) in high pressure cylinders is the most economic storage option however liquified hydrogen (20K) stored in cryogenic tanks is a better option if high energy density is more critical [19]–[21]. Cold or cryo-compressed hydrogen and material-based hydrogen storage technologies such as metal hydrides, chemical hydrides and sorbents are seen to hold the most potential for achieving the U.S Department of Energy (DOE) targets for FCEV storage in the future [22].

In comparison, the challenge for large-scale stationary applications is ensuring a high volumetric density for hydrogen without consuming an excessive amount of energy in the form of work/heat or hydrogen binding to materials, all of which significantly increases the cost of storage. The majority of studies on large scale hydrogen storage focus on the potential of underground geological storage such as salt caverns, depleted oil & gas reservoirs, aquifer storage and the operational characteristics of each. [4], [23]–[26]. Most studies state that compressed hydrogen storage (up to 200 bar) in salt cavern storage is the most feasible form of large-scale hydrogen storage. It is also the only geological storage form which is currently operational, specifically in Teeside, UK, and Texas, USA. Lord *et al.* addressed the geological storage potential in the US by conducting an economic analysis based on developing and operating the four types of storage mentioned above. The study identified salt cavern storage holds the most potential as multiple loading cycles per year can be achieved. The LCOS of salt cavern storage is calculated to be 1.61 \$/kg for a volume of 580,00 m³[27].

Barthelemy *et al.* provide a holistic overview of most hydrogen storage technologies from a materials perspective and mention that composite pressure vessels hold the most potential for high pressure (700 bar and higher) compressed hydrogen storage however there are still challenges to overcome in terms of durability and reliability. The study also found that pressure vessel storage and cryogenic hydrogen storage are the most mature hydrogen storage technologies for stationary applications, but they are not economically viable on a larger scale [28].

Some studies also analyse the feasibility of large-scale hydrogen storage specifically for seasonal storage. Through conducting a techno-economic assessment of grid-integrated seasonal storage technologies for the US grid (84% renewable generation assumed), Omar *et al.* identified that between pumped hydro storage (PHS), compressed air, and hydrogen seasonal storage, hydrogen presents the most cost-competitive case when considering one week of discharge duration. This is under the assumption that capital costs for geological hydrogen storage reduce to below 1.8 \$/kWh by 2025 and electrolysis and power generation equipment costs reduce to below 1507 \$/kWh (considering a 40% round trip efficiency and a lifetime of 18 years) [29].

In a net energy analysis comparing a lithium ion battery system (LIB) and a regenerative hydrogen fuel cell (another possible seasonal storage alternative) Pellow *et al.* found that although the battery system had a higher overall energy efficiency, 83% compared to 30% of the RHFC, the latter offered a higher energy returned on investment, a ratio of 59 as compared to a ratio of 35 when assessing which technology would be best for capturing overgeneration from wind turbines [30]. The study also found that underground storage is more favourable than above-ground pipeline storage or pressure vessels for hydrogen storage.

There is also ample research concerning material-based hydrogen storage. Hydrogen storage through adsorption involves physical bonding of van der Waals between hydrogen and an adsorbent such as porous carbon-based materials, metal-organic frameworks (MOFs) and zeolites. These storage pathways have only been applied on a laboratory scale and require significant thermal management due to the amount of heat released in the process. Even the most promising adsorbents suffer from a low share of hydrogen by mass [7], [31]. Hydrogen can also be stored with chemical hydrides, metal hydrides and liquid organic hydrogen carriers (LOHCs) through chemisorption. Metal hydrides can be further categorized as elemental metal hydrides, intermetallic hydrides and complex hydrides [32]. MgH_2 is the most promising elemental metal hydride due to the low material costs for magnesium although the hydrogenation and dehydrogenation enthalpy of the reaction to form the hydride is very high (75 kJ/ mol) implying that it is not easily reversible even though the share of stored hydrogen achieved (approximately 8% by mass) is relatively high. Intermetallic hydrides have very high costs associated to them and complex metal hydrides require very high temperatures for dehydrogenation [33].

LOHCs are storage systems that can be reversibly dehydrogenated and hydrogenated (in the presence of a catalyst at elevated temperatures) and are liquid in both forms at ambient conditions. The most researched LOHCs are all aromatic compounds prior to reaction with hydrogen and can reach volumetric densities of 64 kg/m³ (dibenzyltoluene and perhydro-dibenzyltoluene) [32], [34]. The main benefits of LOHCs are their ability to be utilized with the existing fuel infrastructure, maintain a high purity of hydrogen and finally be easily transported over long distances in tankers, by rail etc. Although it is a promising storage solution for hydrogen it has mostly been researched as a hydrogen transportation mechanism rather than for stationary storage [35].

Andersson *et al.* conducted a very comprehensive analysis on material-based large-scale hydrogen storage solutions and identified that ammonia, methanol, magnesium hydride (MgH_2) and aluminium hydride (AlH_3) achieve volumetric storage densities that are competitive with liquid hydrogen and consume less energy. The study also concluded that LOHCs require less energy for the total storage process as compared to conventional compressed storage, although they require more heat which makes them more suitable for industrial applications [32].

Chemical hydrides achieve a higher volumetric density as compared to metal hydrides. The main forms are ammonia, methanol and formic acid. The processes of converting hydrogen into ammonia or methanol are already well established. Together with the production of methane, these conversion pathways are often generalized as Power-to-X processes (PtX), and the chemicals are often referred to as electro fuels. These have already been identified within literature to be viable alternatives to hydrogen storage for storing excess renewable electricity [36]–[38] with significant focus on the cost of production, and the round-trip efficiency associated to the fuels taking into consideration production, storage and transportation. and studies have analysed their cost of production in depth [39], [40]. R auchle *et al.* calculated that the process of power-to-methanol-to power has an overall higher efficiency (45%) as compared to the equivalent for methane however the study did not focus on specifically the storage costs and the analysis did not include hydrogen [41]. The production process for each aforementioned fuel is elaborated later in this study.

Overall, it can be stated that the research surrounding hydrogen storage options is quite diverse and covers a wide range of technologies. Moreover, the potential of power-to-gas (PtG) and power-to-liquid (PtL) processes as energy storage methods have already been recognized yet there is less information regarding the economic cost of storing each fuel for seasonal storage purposes.

1.2. Research Objective and Questions

The objective of this thesis is to determine the economic feasibility of utilizing green hydrogen as compared to other carbon neutral fuels, specifically, methane, methanol and ammonia as long-term energy storage. The main aspects considered within this analysis are: the cost of the storage mechanisms, the cost of loading the fuels into the storage, if there are any significant leakages associated to the storages, and advantages and disadvantages of utilizing each fuel given its physical properties and the maturity of its production. The outcome will be a model that calculates the LCOS for each fuel for specific storage types.

The following research questions have been outlined to achieve this:

- What are the economic costs of different storage types for carbon neutral fuels considering technical characteristics?
- What is the levelized cost of storage of each fuel when utilized as seasonal storage compared to a daily or annual storage?

Scope and limitations

The thesis focuses on developing a model that calculates the storage cost of different carbon neutral fuels within industrially introduced storage forms. It is a conceptual model that is not created based on a specific case study or based on data from a pilot plant however it can be adapted for such purposes.

The model does not consider the end use of the fuel and does not optimize the usage of storage. The study is limited by the usage of a scaling factor within the storage model. The financial data from literature is multiplied by a scaling factor in order to ascertain the ‘real’ cost of storing fuel required to meet the specified energy requirement.

2. Energy storage for grid stabilization

This section provides context to the research problem, namely, the need for seasonal storage, different types of flexibility on the grid and why battery energy storage (BES) systems alone will not suffice.

2.1. Limitations of battery energy storage

Energy storage technologies (ES) can be divided into three main categories, short, medium and long term based on their discharge time, Table 1 provides the classification of the typical power rating and discharge time for present day ES technologies and their applications [42]. Currently BES are the most technically feasible form of ES but their short discharge times (up to 4 hours) make them only suitable for fast response grid stability issues and intraday variations [43]. In order to reach a 100% RES on the grid, ES must reach durations of 100+ hours and be able to withstand discharging and charging over a timeframe of months to meet the seasonal mismatch between supply and demand of RES.

Table 1: Overview of energy storage applications depending on the storage duration and power rating required [42], [44]

Storage Duration	Power Rating	Applications	Technology Utilized
$\leq 1\text{min}$	$\leq 1\text{ MW}$	Power quality & regulation e.g. voltage control, reactive power control	Supercapacitors & flywheel energy storage
1 min - 1 h	10 – 100 MW	Power bridging e.g. spinning/contingency reserves, ramping	Redox flow batteries
1min -8h		Peak shaving	Lead acid (Pb-A) & LIB
5-12h	$\geq 300\text{ MW}$	Energy arbitrage	Compressed air energy storage (CAES)& pumped hydro storage (PHS)
Hours – days		Load levelling, diurnal variation of RES	
$\geq 4\text{months}$		Seasonal storage	

LIBs, which dominate the short-term storage market, are economically unviable for long energy durations owing to their high energy capital costs [45]. Storage technology, unlike conventional generation, is usually defined by both a power (kW) and an energy (kWh) cost component where the former is dependent on the conversion equipment e.g. invertors or compressors, while the latter is dependent on the storage medium.

Figure 2 compares recent cost estimates for different ES technologies. It is evident that LIBs have much lower power component costs (246 \$/kW) as compared to technologies such as PHS (1151 \$/kW) and hydrogen storage in a cavern (1675 \$/kW) but higher energy component costs than the latter (320 \$/kWh). This implies that LIBs are not the best options for long duration storage since their energy costs will incrementally increase every hour by a much larger amount than the other storage technologies mentioned. This is the main factor leading to the infeasibility of LIBs for LTES.

Apart from this, there are several other issues limiting wide scale application of batteries. Firstly, they exhibit degradation over their lifetime due to increasing internal resistance, material degradation of electrodes as a result of parasitic reactions during high state of charge (SoC) and a multitude of other factors depending on their usage [46]. Leaving a LIB discharged for long periods of time could also lead to copper dendrite formation and increased instability [47]. Secondly, material usage for large scale production (3000 million tonnes of lithium if solely solar and wind were to meet the global energy demand in 2020) is a critical problem [48]. Thirdly, manufacturing of batteries negatively impacts the environment; 0.3 kWh of energy and 800 L of water is required to achieve 1 kWh of storage capacity and a range of 40–340 kg/kWh of GHG emissions are emitted throughout the life cycle of batteries [49].

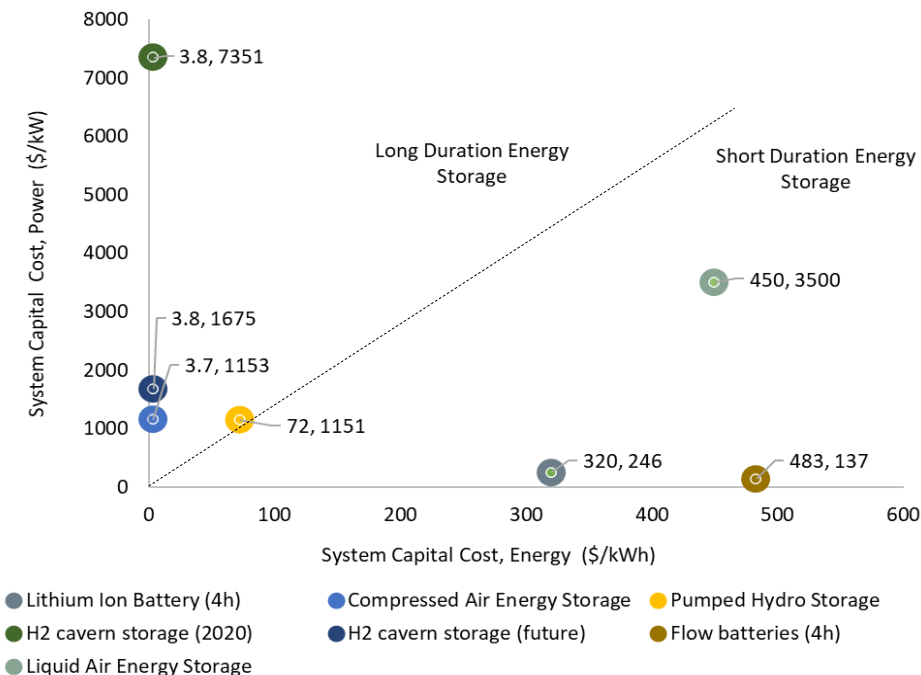


Figure 2: Power specific vs energy specific costs of different ES technologies [164]

2.2. Flexibility in a power system

The Texas blackout crisis in February 2021 can be used to further emphasize the need for large scale storage. An abnormally cold winter in conjunction with lack of weatherized fossil fuel generation and grid interconnections to the other US grids, led to ERCOT issuing rolling blackouts to relieve pressure on the grid. Flexgen, one of the largest installers of battery storage in Texas, specified that short duration storage has the potential to enable ‘black start’ situations where batteries can be utilized in lieu of diesel generators to restart the grid but they will not be able to meet multi-day variations of the magnitude required [50]. Although LIBs provide a certain type of ‘flexibility’ to the grid they are not suitable for providing different types of flexibility that are also crucial to an efficient and reliable grid.

Implementing ‘flexibility’ to a power system can manifest itself in multiple ways depending on different timescales. The crux is to ensure energy security and resilience; a brief definition of the 5 key types of energy security are mentioned below. Figure 3 provides a framework with a summary of different types of flexibility measures and the appropriate ES technologies that fit the role.

- **Stability:** This refers to the ability of a system to meet unexpected disturbances or loss of critical equipment with a fast response e.g. loss of a generation unit and ensuring voltage and frequency requirements are met by setting standards such as $N-1$ [5].
- **Flexibility:** This refers to meeting the diurnal patterns of variable renewable generation, adapting to stochastic patterns in load variations and finally meeting the seasonality of renewable generation and demand e.g. ensuring dispatchable generation and adequate interconnections on the grid [5].
- **Resilience:** This refers to the ability for a power system to absorb the shock of switching to an alternative mode of production, both from a technology and energy market perspective, in case of an unavailable critical resource e.g. natural gas supply [51].
- **Adequacy:** An ‘insurance policy’ to ensure power systems are equipped to overcome emergency situations which are stochastic and occur less than once a year e.g. the Texas case with a very cold period with very low wind and solar generation. It ensures that the grid will always be able to meet the demand, regardless of exogenous or endogenous factors. It also involves ensuring appropriate regulation is in place for market adequacy e.g. maintaining competition or incentivising investment to ensure continuous improvements are made to infrastructure in a timely manner [51].

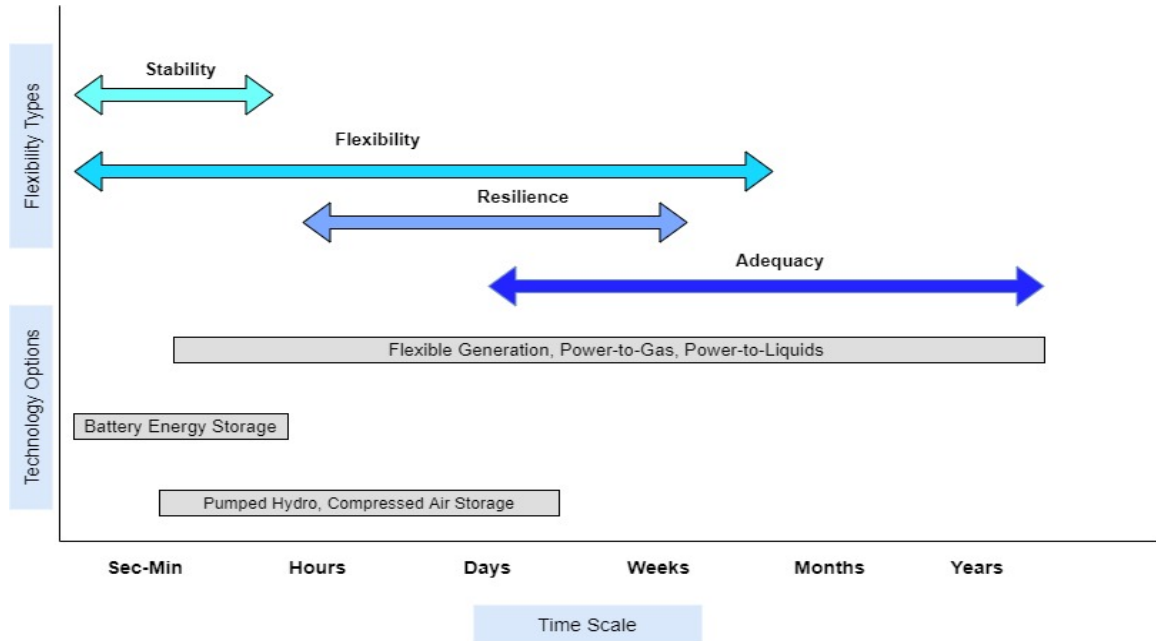


Figure 3: Different types of flexibility measures that can be implemented in a power system, the time scales for each and the main technologies that can be utilized to provide this flexibility

2.3. Current types of LTES

The most mature long-term storage technologies that exist today are PHS and gas storage. PHS is seen to have reached its economically viable and technical potential due to geographical and environmental constraints. Additionally, the reliance on natural gas is inconducive to reducing dependence on fossil fuels [52]. These alone will not be viable, other technologies are needed to balance the seasonal variations between production and supply. The considered solutions include demand side flexibility, sector coupling, PtX and increasing interconnections on the grid.

As alluded to earlier, PtX is an umbrella term for energy conversion processes that enable the usage of excess power on the grid and hold the most potential for storing energy feasibly at a TWh scale [3]. The pathways most relevant to this study are:

- Power-to-Hydrogen (PtH): Involves utilizing excess electricity for the electrolysis of water to produce hydrogen. Hydrogen can then be used as an energy carrier (storage medium) or as an end use fuel to produce electricity again.
- Power-to-Gas (PtG): Hydrogen produced via electrolysis is synthesized using methanation to produce synthetic methane which can be injected into the natural gas grid or utilized as a secondary energy carrier.
- Power-to-Liquid (PtL): Syngas is upgraded to a liquid fuel utilizing the Fischer Tropsch process or converting to methanol or DME [53].

More recent seasonal storage solutions include liquid air energy storage (LAES) and compressed air energy storage (CAES). LAES involves utilizing excess electricity to compress air and then storing it at cryogenic temperatures. It has gained a large amount of market traction; led by UK's Highview Power which recently cemented a 500 MWh project in Chile [54]. CAES is limited by the usage of natural gas to expand air and is not yet competitive against incumbent gas storage in terms of energy efficiency and technological maturity.

Other nascent technologies that are aspiring to break through the market are redox flow batteries, iron-air batteries which work through the reversible oxidation of iron and are built for >150 hr durations and other novel solutions such as thermochemical reactions for building heating e.g., converting calcium hydroxide to calcium oxide and water vapour in ambient storage mediums on site [55]–[57]. Storing thermal energy in the form of sensible heat, latent heat or thermochemical heat is also a potential option for seasonal energy storage, especially in cold countries where the heating sector needs to be co-optimized with the energy sector. Sensible heat storage (SHS) is the most mature type of thermal energy storage, with synthetic oil and molten salt being the most common SHS materials utilized in large-scale concentrating solar power (CSP) systems [58]. On a smaller scale, low-temperature seasonal thermal energy storage utilizing heat pumps and solar heat collectors is emerging as an energy and cost-efficient solution for the residential and commercial sector [59].

3. Overview of carbon neutral fuels

This section is a continuation of the background of the study and provides a brief overview of the production methods of hydrogen, methane, ammonia and methanol, current production costs and the barriers to their commercial use as energy storage.

3.1. Power-to-Hydrogen

Hydrogen (H₂) is gaining unprecedented momentum in the energy market yet for hydrogen to be a feasible renewable energy storage alternative, it must be produced through electrolysis utilizing renewable energy. Current global hydrogen production is dominated by steam methane reforming (SMR) of natural gas and gasification of coal with less than 0.1% produced utilizing electrolysis. Therefore, hydrogen production is associated with 830 million tonnes of CO₂ emissions per year [9].

Hydrogen production is divided into five main types [60]:

- grey hydrogen is produced through SMR (black hydrogen is produced from the gasification of coal)
- blue hydrogen is produced using SMR, however, carbon capture and storage technology (CCS) is utilized for capturing the carbon dioxide produced as a by-product of SMR

- green hydrogen is produced through electrolysis utilizing renewable electricity
- purple hydrogen is produced utilizing nuclear energy for electrolysis
- turquoise hydrogen is produced using methane pyrolysis which also produces solid carbon

3.1.1. Hydrogen Production

There are three methods of producing green hydrogen – alkaline (AEL), polymer exchange membrane (PEM), and solid oxide electrolysis (SOE). Important characteristics of each are provided in Table 2. Out of the three, AEL is the cheapest and most mature technology, although, it suffers from a long start-up time due to the inflexibility of its auxiliary equipment. PEM is currently a more expensive technology due to its expensive catalysts but is best suited for PtX applications because of its fast load-change capability. SOE has a higher electrical efficiency than the latter technologies. The disadvantage of SOE is the high heat requirement for the process and that it is currently only available at a demonstration level [61]–[63].

All electrolyzers are composed of a stack where the chemical splitting of water occurs and auxiliary equipment which includes power supply, water supply, oxygen and hydrogen buffer units and finally hydrogen processing units. The hydrogen processing is dependent on the type of electrolysis but generally, to ensure high purity of hydrogen, the gas is catalytically deoxidized in a ‘DeOxo’ unit to remove any traces of oxygen. This is usually followed by gas drying to remove the water vapour produced through oxidation [64], [65].

There are multiple PtH plants that are currently operational worldwide and there are even more in construction that are expected to be operational from 2025 onwards. The Australian company Enegix is in the process of building one of the world’s largest green hydrogen plants in Brazil. Estimated to provide more than 0.6 Mt of hydrogen per year, the facility is expected to be operational by 2025 [66]. Oman is also building one of the largest green hydrogen production facilities. Powered by 25 GW of solar and wind energy, it is expected to be fully operational by 2038 and produce 1.8 Mt of green hydrogen and up to 10 Mt of green ammonia a year [67].

Table 2: Main operating characteristics of AEL, PEM and SOE electrolyzers

Characteristics	AEL	PEM	SOE
Operating Pressure (bar) [61]	<30	<200	<25
Operating Temperature (°C) [61]	60-80	50-80	650-1000
Electrical efficiency (% LHV) [68]	63-70	56-63	74-81
CAPEX (€/MW_{H2out}) [69]	0.9-1.8	1.6-3.0	2.1-3.8
Stack lifetime (h) [68]	50,000-90,000	30,000-90,000	10,000-30,000
Maturity	Mature	Commercial	Demonstration

3.1.2. Barriers to commercialization

In the hopes of achieving a hydrogen economy many countries have incorporated hydrogen utilization targets in their national climate strategies. One example is the EU Hydrogen Strategy which aims to achieve the installation of at least 6 GW of electrolyzer capacity in the EU by 2024 (producing 1 Mt of hydrogen) [70]. Another target within the strategy is to make green hydrogen a mature technology between 2030-2050. Moreover, the adoption of green hydrogen targets by countries such as Australia, China, and several countries in Latin America has also led to surge in investment in electrolyser projects [71]. According to Aurora, 213.5 GW of electrolyser projects are slated for delivery by 2040, an increase by three orders of magnitude from the current 0.2 GW [72].

Nonetheless, there are still major barriers for commercial application of green hydrogen as a seasonal storage technology. Besides the scale-up of electrolysis projects, for green hydrogen to become a feasible energy carrier, it must also reach cost parity with grey and blue hydrogen. The realization of this highly dependent on three factors: an increase in carbon prices, electrolyser cost decrease through economies of scale and that hydrogen-specific infrastructure develops as predicted. According to the European Commission (EC), in 2020 grey hydrogen costs 1.5 €/kg, blue hydrogen costs 2 €/kg and renewable hydrogen costs 2.5-5.5 €/kg in the EU.

Moreover, the Commission has estimated that a carbon price of between 55 to 90 €/t will be needed to make blue hydrogen competitive against grey hydrogen today, indicating that a much higher price would be required for green hydrogen to become competitive [73].

Furthermore, hydrogen is a precursor for other critical fuels and chemicals, its production must meet the demand from industry as well as the energy sector for it to be utilized as seasonal storage. To put the energy storage demand for green hydrogen in perspective, a country with a net average monthly renewable load of 50 GW would require approximately 3×10^{17} J or 2.6 million tonnes of green hydrogen to meet its long duration energy storage requirement (assuming green hydrogen will only be utilized to meet the final 1-3% of demand in a 100% RES grid). This represents 3.5% of current global production. This value would be higher considering supply chain losses such as boil off from liquid, conversion losses and leakages, implying that green hydrogen production must be scaled up rapidly in order to enable its use as seasonal energy storage.

Increasing green hydrogen production to this level is also heavily reliant on significant build out of renewable energy capacity. A recent report co-authored by the Hydrogen Council and McKinsey & Company stated that achieving net-zero by 2050 requires close to 660 MMt of green hydrogen [74]. This would require 6500 GW of renewable generation capacity, approximately 3500 GW more than the global capacity at present.

Generally, the main impediments to the proliferation of hydrogen in the energy landscape are the following[75]:

- Lack of appropriate storage, transportation and distribution infrastructure such as pipeline networks
- High CAPEX costs due to high costs of equipment, compression technology and especially electrolyser costs
- Lack of reliable and comprehensive hydrogen supply chain
- Achieving sufficiently low prices of renewable electricity
- Lack of appropriate legislation and decarbonization targets
- Non- utilization of by-products e.g. waste heat and oxygen
- Sluggish growth in carbon prices
- Low public acceptance

The challenges of hydrogen storage will be discussed in Section 5.

3.2. Power-to-Methane

Methane (CH₄), the primary component of natural gas, can be utilized in all relevant end use technologies for natural gas such as gas turbines and internal combustion engines (ICE). Utilizing synthetic methane, otherwise known as synthetic natural gas (SNG) solves the challenges associated not only with storing and distributing hydrogen but also converting the fuel back into energy [39].

This is extremely advantageous since there is still major development required to be able to burn hydrogen in high concentrations with ICE due to its high autoignition temperature, large flame travel distance and the embrittlement it may cause in engines [76]. In terms of storage, methane also has a higher density than hydrogen and around 1000 TWh of methane storage capacity is already operational globally [77]. For these reasons, PtG has gained significant traction as an option to increase integration of renewables on the grid.

3.2.1. Synthetic Methane Production

Carbon neutral SNG is produced either by thermochemical methanation, also called the Sabatier reaction, or by bio methanation using hydrogenotrophic methanogenic archaea. Both processes require renewable hydrogen and captured CO₂ as feedstock [78].

The Sabatier reaction is a highly exothermic reaction which involves a two-step process carried out in a catalytic reactor at temperatures of 150- 550°C depending on the catalyst and pressures of up to 100 bar [79]. The process is very sensitive to changes in thermodynamic conditions and high operation pressures are preferred for a higher yield of methane. Nickel is the most economic catalyst utilized however ruthenium and rhodium have a higher specific activity [80].

The first step involves creating carbon monoxide (CO) and steam from CO₂ and H₂ via an inverse water gas shift reaction. The second step is the final synthesis of methane from CO and H₂. A disadvantage of this process is that feed in gases are required to have a high purity prior to the reaction since the metal catalyst is extremely sensitive to impurities e.g. hydrogen sulfide. Typically, this process has an efficiency of 75% on an HHV basis [77].

In comparison, bio methanation occurs at relatively low pressure and temperature, 30-40°C and 90 bar, and is less sensitive towards impurities in the feed-in gas. Nonetheless, the process has a lower space and time yield as compared to the thermochemical route thus requiring larger reactors. Due to this, it is economically less competitive [79]. An emerging pathway capitalises on the ability of SOECs to co-electrolyze both steam and carbon dioxide for *in situ* synthesis of methane in a single reactor [81].

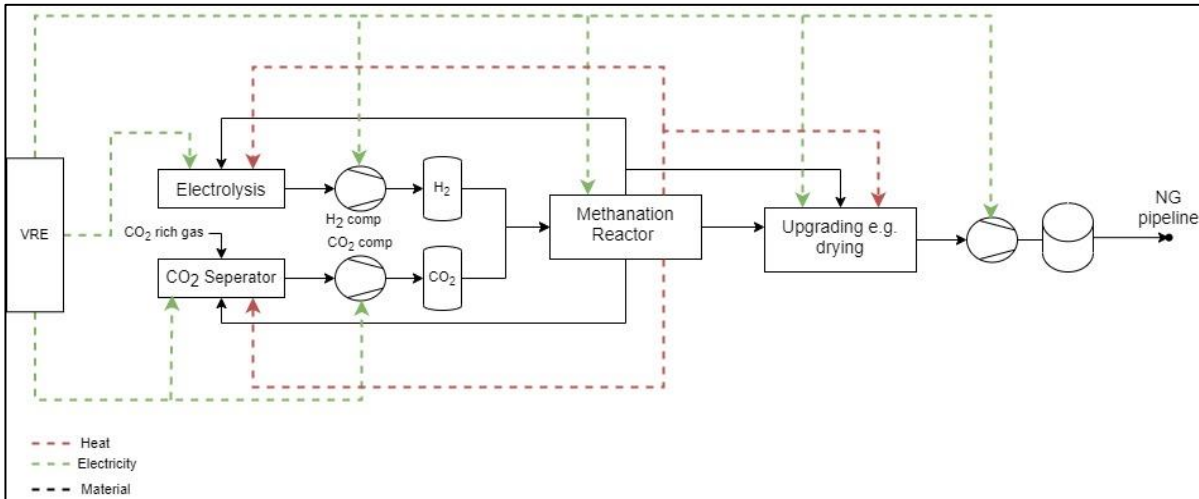


Figure 4: Basic process of a P2G plant. Based on [81], [165]

The general system components of a PtG plant are shown in Figure 4. The main components, addition to the electrolyzer, are the CO₂ separator (in case pure CO₂ is unavailable), CO₂ compressor, methanation reactor, SNG drying (upgrading) unit, SNG compressor if required and a SNG storage vessel. Most PtG plants are currently operating on a demonstration scale. The Audi E-Gas plant in Werthe, Germany built by ETOGAS, is the only industrial PtG plant and produces SNG at a rate of 1000t/year. It utilizes 6 MW of electricity (powered by an offshore wind park) to produce hydrogen through AEL and utilizes CO₂ captured from biogas through amine absorption [36].

3.2.2. Barriers to commercialization

A major barrier to the PtG pathway is that carbon neutrality will only be achieved if captured CO₂ is readily available. This depends on if CCS technologies reach technological maturity and are cost effective to be implemented on a large scale. Concentrated CO₂ is a by-product of several industrial processes such as the production of ethanol, methanol and ammonia. Other possible point sources include iron, steel and cement plants. At present CO₂ is mainly obtained from post-combustion capture in which it is extracted from exhaust gases at powerplants. Pre-combustion capture involves gasifying fuel and separating CO₂ before capture and is uncommon [82].

Moreover, the only process for removing CO₂ directly from the atmosphere, direct air capture (DAC) is yet to be demonstrated on a large scale. It is limited by its significant chemical sorbent demand and high energy requirement. DAC will require up to 300 EJ/year of energy input to achieve 1.5 GtCO₂/year capture (year 2100 estimate) [83]. According to the International Energy Agency (IEA), its feasibility remains uncertain and future cost estimates are speculative, ranging from \$100/t to \$1000/t depending on technology developments [84].

Another concern of PtG is the large amount of heat produced through the methanation reaction which leads to significant losses for the whole process if unused. Lindorfer *et al.* found that, when comparing the overall efficiency of injecting hydrogen into the gas grid as opposed to injecting SNG, the additional equipment required for the methanation process makes it 10% less efficient on a long-term basis [85]. Furthermore, PtG technology has not reached technological maturity (TRL 5-7) owing to high CAPEX costs and lack of CO₂ availability. Although with significant investment into carbon capture technology and the expected decrease in electricity prices, it could become a viable option for energy storage [36].

3.2.3. Storage

Since compressed natural gas (CNG) is elementally mostly methane, SNG can be stored without dominant technical barriers as the storage technology is which has well established and mature [86]. Most existing large scale CNG storage capacity is within depleted oil and gas reservoirs with existing wells and surface handling facilities. These types of underground formations can also host methane without any major modifications and have the required permeability for achieving high injectivity and deliverability rates. Natural gas has also been stored in aquifers, salt caverns and rock caverns [87].

3.3. Power-to-Methanol

Methanol (CH₃OH) is a critical feedstock in the chemical industry for producing formaldehyde, acetic acid, olefins, dimethyl ether and other liquid fuels and chemicals. It can also be mixed in gasoline and utilized as a drop in fuel in vehicles (M85). It is a promising contender from an energy storage point-of-view since it is liquid at ambient conditions (1 bar and 25°C) which increases its cost effectiveness in transportation and distribution. Studies have also shown that it can be produced at a higher overall efficiency compared to SNG [37], [88].

3.3.1. Synthetic Methanol Production

Today, methanol is produced through a catalytic reaction that requires CH₄, CO₂, and steam (H₂O) as feedstock. The first step in the process involves a highly endothermic steam reforming reaction to produce CO and H₂ from CH₄ and H₂O. The second step is a dry reforming reaction that utilises CH₄ and CO₂ to produce CO and H₂, together with steam as an input for heat. These two steps are combined in presence of a CZA (Cu/ZnO/Al₂O₃) catalyst, which is the industry standard. Overall, methanol synthesis is exothermic and is performed at low pressures of 60-80 bar and high temperatures of 200-450°C [89]. Generally, the reactor produces crude methanol which undergoes distillation separation in order to purify the product [90].

The general process of a power-to-methanol (PtM) plant is illustrated by Figure 5. It involves (i) H₂ production through electrolysis; (ii) CO₂ capture from exhaust gases or alternative CO₂-rich sources and compression to increase the pressure of CO₂ to match that of the H₂ feed, (iii) a compressor to mix and pressurize H₂ and CO₂, (iv) a heat exchanger to recover heat from the methanol reactor to preheat the H₂/CO₂ mixture, (v) a methanol reactor for methanol synthesis, (vi) a distillation/separation unit section to produce pure methanol and to recover any unreacted gas, (vii) a recirculation compressor to transport the unreacted gas to the compression mixer.

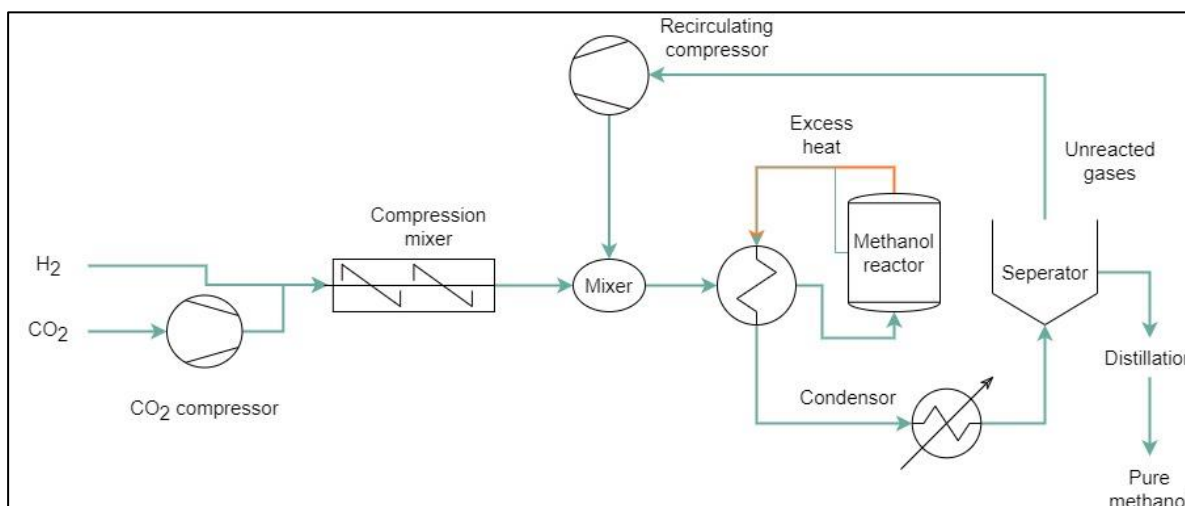


Figure 5: Overview of PtM process. Green lines indicate material flow and orange line indicates heat flow Based on [37]

There are a few commercial PtM plants in operation; most are at a demonstration scale. The most notable project is run by an Icelandic company, Carbon Recycling International (CRI), a global front-runner in green methanol production. The company operates a commercial methanol plant in Grindavik, Iceland, that utilises geothermal power and CO₂ from Svartsengi, a geothermal power station, to produce 4000 t of methanol annually [88].

3.3.2. Barriers to commercialization

Currently, methanol is produced utilizing natural gas reforming and coal gasification at a cost of 200-250 €/ton, which is significantly lower than the cost of methanol from biomass gasification (500-600 €/ton) and hydrogen electrolysis with direct capture of CO₂ (ranging from 900-1,400 €/ton). The reduction of this gap hinges on a decrease in renewable power prices, an increase in carbon prices and electrolyser technology reaching economies of scale. The PtM conversion efficiency is ca. 50% and the cost of methanol production ca. 800 €/ton for a production process involving a 100 MW stand-alone wind turbine fleet, including the capital cost of wind turbines [37].

The methanol synthesis system itself contributed to 5% of the total capital cost of the system (excluding wind turbine investment costs), signifying the PtM process can be a feasible option soon. A technical barrier to PtM is that the process results in significant water output in the reactor bed which leads to decreased efficacy of the catalyst, thus there are modifications that need to be carried out in the synthesis process if it were to be implemented on a large scale [91].

3.3.3. Storage

Methanol is a highly flammable, hygroscopic and corrosive chemical; thus, its storage procedure must be implemented with the utmost precision. It is predominantly stored in cylindrical austenitic or carbon steel storage tanks with double containment and a storage volume of up to 114 m³ [92]. Due to its tendency to absorb water coupled with its relatively high conductivity methanol can sometimes cause stress corrosion cracking (SCC) of high carbon or austenitic steel [93]. Tanks must also be grounded to prevent static discharge hazards. Usually, the risk of fire hazard as well as contamination by water from the ambient air is mitigated by padding the vapor space in the tank with a dry inert gas such as nitrogen and controlling the ignition sources near to the tank [93].

3.4. Power-to-Ammonia

Ammonia (NH₃) is one of the most important industrial chemicals. Its global production reached 187 Mt in 2019 of which 75% was utilized by the agricultural sector as fertilizer and the rest was used in the manufacturing of plastics and, refrigerants, and in purification of exhaust gases from power plants [94]. Hydrogen is a critical precursor for ammonia (17.65 % by mass) [95].

Apart from being a critical feedstock for the fertilizer industry, ammonia is a promising low-emission fuel for maritime applications and for fuel cells, ICEs and gas turbines. Several companies are developing MW-scale testing projects for ammonia-powered ICEs, forecasted to be ready by 2024-2025 [96]. Because of the possibility of using ammonia as a fuel, power-to-ammonia (PtA) is a promising green hydrogen carrier to be used as a seasonal energy storage. Methane and methanol both have their advantages as energy vectors: methane can be injected directly into the gas grid, whereas methanol is liquid in ambient conditions and easy to transport. However, both require CO₂ as an input and release it upon combustion.

Ammonia, on the other hand, is a carbon free chemical much like hydrogen but is easier to store in large quantities and transport over long distances than hydrogen mainly due to its higher volumetric energy density (7.1 MJ/L vs 2.9 MJ/L of H₂) and ease of liquefaction [97]. Agencies such as IEA consider ammonia to be viable energy carrier which has encouraged its acceptance from a policy perspective [98].

3.4.1. Synthetic Ammonia Production

Conventionally ammonia is produced through the thermochemical conversion of hydrogen and nitrogen in the presence of an iron oxide-based catalyst using the high pressure (150-250 bar), high temperature (400-450°C) Haber-Bosch (H-B) process [99]. This has traditionally required hydrocarbon feedstocks such as natural gas, coal or heavy fuel oil, and has led to ammonia production accounting for 1-2% of global GHG emissions[100].

Although the emission intensive nature of this process is no longer an issue when using renewable energy, the challenge that the process has almost reached its technical efficiency potential remains. The total system efficiency of ammonia synthesis is 46%-55% [101]. Furthermore, conventional ammonia plants have utilized grey hydrogen in conjunction with H-B. These processes have been co-optimized over years and considering green hydrogen is much more expensive than blue and grey hydrogen as of now, the production of green ammonia requires significant investment into electrolyser technology [102].

A less energy-intensive alternative to H-B is electrochemical ammonia synthesis from hydrogen and nitrogen gases. This process is still in early stages of development but requires approximately 20% less energy for the equivalent ammonia production through H-B. Another pathway involves a thermochemical cycle which can be conducted at atmospheric pressure without a catalyst [38].

The basic PtA pathway consists of three main steps (see Figure 6): (i) production of hydrogen utilizing renewable electricity, (ii) using renewable power in an air separation unit to produce nitrogen, usually cryogenic, and (iii) reacting nitrogen with hydrogen through H-B powered by renewable electricity. In order to address the heat produced through the exothermic synthesis reaction that produces ammonia, high temperature SOE coupled with H-B holds the most potential [103]. Furthermore, a low temperature H-B is being developed through photoelectrochemical and electrochemical pathways [104].

Green ammonia can be more advantageous as compared to hydrogen as an energy carrier if storage feasibility is considered in isolation (without considering the life cycle of the chemical). This is because it can be rendered liquid at ambient temperature and low pressure (10 bar) and it has an established and reliable transportation and distribution network [105]. Additionally, it has a lower cost per unit of stored energy; [97] found that over 182 days ammonia storage has a cost of 0.54 \$/kg-H₂ compared to 14.95 \$/kg-H₂ of pure hydrogen storage.

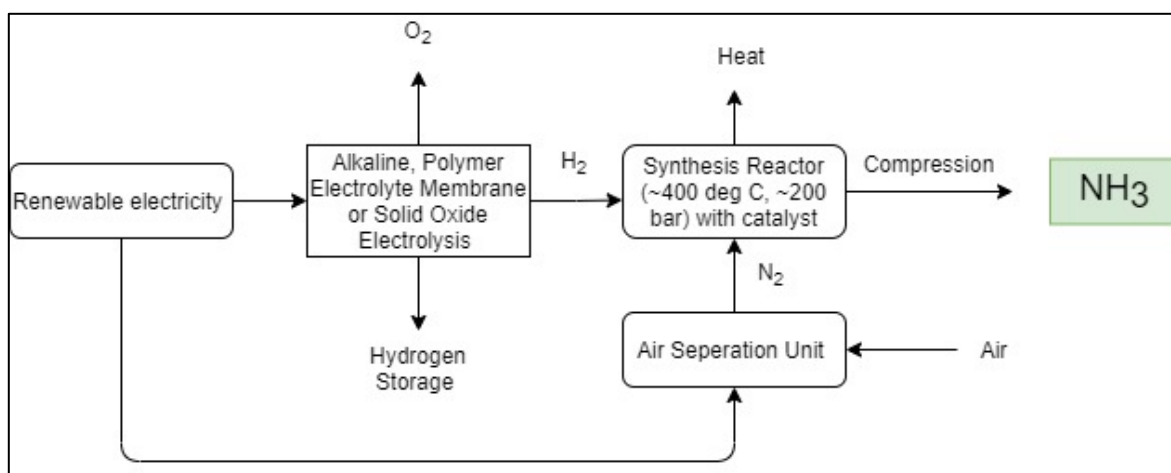


Figure 6: General PtA process,[106]

A study conducted by the analysis house IHS Markit concluded that green ammonia could be cost competitive against grey ammonia by 2030 in North America assuming AEL is utilized to produce hydrogen and utility scale solar levelized cost of electricity (LCOE) are considered. They also identified that the results is highly dependent on the projected decline in renewable electricity prices, from 40 \$/MWh in 2020 to 20 \$/MWh by 2030 [94]. In another study investigating the global potential of green ammonia, Fasihi *et al.* found that green ammonia could be generated at a cost of 260–290 €/t (WACC of 7%) in 2030 compared to the current decade-average cost of grey ammonia of 300–350 €/t [106].

The number of industrial PtA projects is rapidly growing. A company Proton Venture already offers small scale PtA systems which will utilize excess renewable electricity to produce close to 20,000 Mt of ammonia per year [107]. Another company, NEOM, has signed an agreement worth \$5B in conjunction with ACWA Power and Air Products for the development of a large-scale green hydrogen-based ammonia production facility in Saudi Arabia. The expected capacity of the plant is 650 t of hydrogen per day and 1.2 Mt of green ammonia per year. Production is expected to commence in 2025[108].

3.4.2. Barriers to commercialization

Ammonia production will invariably compete against utilizing hydrogen for seasonal storage if these industries are not developed in tandem considering the large amount of hydrogen required to meet storage needs on a country level. If the appropriate policy and legislation to enable harmonious production, distribution and storage of both fuels is implemented, it could be possible to efficiently couple the industry and energy sectors. However, given the benefits of utilizing ammonia as compared to hydrogen, ammonia could be more feasible as energy storage.

There are some impediments to utilizing ammonia as energy storage. These include the toxicity of the chemical; challenges with ammonia combustion due to slow chemical kinetics, low flame velocity and the high ignition temperature required; and its competing uses in other sectors [109]. Another technical barrier is the low conversion rate of the H-B process. It usually requires recycling of the feedstock and steam circulation to achieve the desired production flow rate. This increases capital and operational expenditure for the PtA process.

3.5. Storage

Ammonia is an appealing chemical for long duration energy storage since it can be stored at a high density for long periods of time without geographical restrictions. It can either be stored as a low temperature liquid in insulated carbon steel tanks (sometimes concrete reinforced tanks) at -33°C and atmospheric pressure or as compressed liquid at > 10 bar and ambient temperature in cylindrical (or spherical) carbon steel pressure vessels. Atmospheric pressure vessels can accommodate up to 50 kt of ammonia and have three main types [110]:

- Single walled tanks
- Double walled tanks with annular (internal) insulation
- Double walled tanks with external insulation

Compressed ammonia vessels can accommodate up to 8 kt of ammonia. The cost of storing ammonia is directly affected by the amount of steel required for storage, thus high-pressure storage is more cost effective. The safety and regulation standards for ammonia storage depend on the country. In any case, it is vital to ensure extensive hydrostatic and leakage tests are conducted since ammonia is a poisonous chemical. The tanks should not be overfilled, and ample space should be left for vapor produced due to temperature fluctuation [111].

4. Hydrogen Compression

All gas storage systems involve two components, a compression process and a storage process. Compression is conducted in order to increase the amount of energy stored within a specific volume of gas. Hydrogen compression differs from the compression of traditional fossil fuels. At elevated pressures, hydrogen deviates from the ideal gas law, and requires a higher volume than predicted [112]. This deviation can be accounted utilizing a dimensionless compressibility factor ‘Z’ within the ideal gas equation so that $PV = nZRT$ [112].

Compressibility factors for a given gas are measured and they depend on temperature and pressure. For a given gas, the critical temperature (T_{cr}) and pressure (p_{cr}) can be used to obtain a generalized compressibility factor. Kell found that for hydrogen at 298 K and 300 bar, $Z=1.2$ [113]. This value for Z implies that the mass of hydrogen in a vessel evaluated with the ideal gas law in these conditions results in a 20% error.

The evaluated compression work required to increase the pressure of hydrogen depends on whether the theoretical thermodynamic cycle of compression is polytropic, adiabatic (isentropic) or isothermal [114]. An isothermal process is the least realistic because it would require infinitely slow compression to maintain isothermal conditions. A polytropic process is a modification of an adiabatic process to represent more realistic conditions. It involves heat transfer between the gas and its surroundings (entropy increases). This process is usually employed by ‘dynamic’ compressors e.g. centrifugal or axial flow. These are more suited for base load applications requiring large flow volume flow rates and work by transforming kinetic energy to static pressure [114], [115]. An adiabatic process is an ideal process that assumes that no heat transfer occurs during compression (constant entropy) but temperature change occurs [114]. Then, the work required for compression is:

$$W = \left[\frac{\gamma}{\gamma - 1} \right] \cdot P_1 V_1 \cdot \left[\left(\frac{P_2}{P_1} \right)^{\left(\gamma - \frac{1}{\gamma} \right)} - 1 \right] \quad (1)$$

Where W (J/kg) is the specific compression work, P_1 (Pa) is the pressure at inlet of compressor, P_2 (Pa) is the pressure at outlet of compressor, V_1 (m³/kg) is the initial specific volume and γ is the ratio of specific heat (adiabatic coefficient). This model is usually applied to ‘positive displacement’ compressors e.g. rotary or reciprocating compressors in practice [116]. These are utilized for moderate flow rate and high-pressure ratio applications.

Figure 7 compares the work required for compression of hydrogen and methane. At any pressure, the compression energy required for hydrogen is larger than that of methane, owing to its lower volumetric energy density. As mentioned, assuming adiabatic compression is the simplest method of calculating compression work. However, an isothermal compression cycle (no temperature change) would result in the least work required for compression and it represents the theoretical minimum work [116].

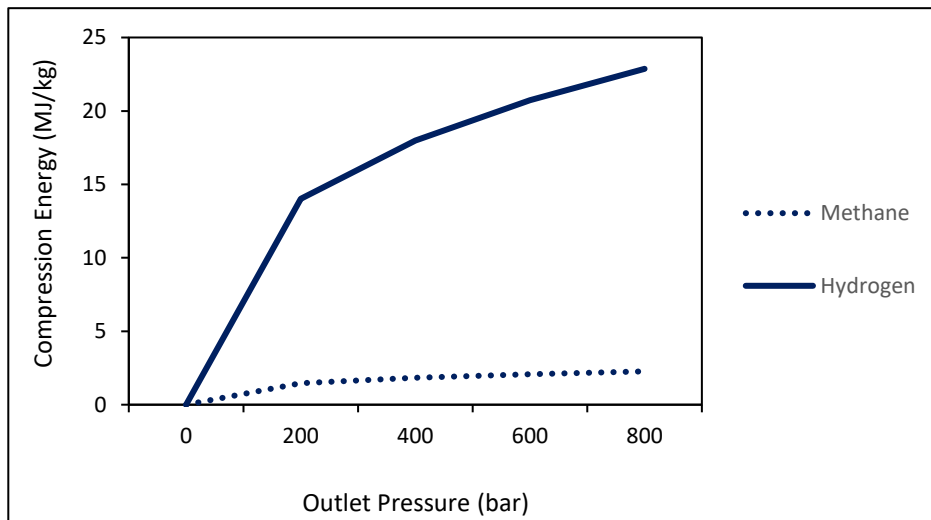


Figure 7: Compression energy required for hydrogen and methane. Data from [116]

Naturally, the isothermal compression cycle cannot be achieved in reality, but in order to emulate the thermodynamic principle, positive displacement compressors have multi-stage compression where the gas is cooled after each stage. The most common compressors in the market for hydrogen are multi-stage reciprocating compressors and centrifugal compressors. Centrifugal compressors designed for natural gas require higher circumferences to achieve higher hydrogen compression due to the low molecular weight of the gas whereas reciprocating compressors for natural gas can be used for hydrogen compression without significant modifications [117]. Thus, the compressor model in this study is modelled based on a single-stage reciprocating compressor based on the adiabatic thermodynamic principle.

5. Challenges of hydrogen storage

High volumetric density is an important characteristic of bulk gas storage in stationary applications. Inopportunately, achieving this for hydrogen at STP conditions is very challenging due to its low molecular mass and low volumetric density [118]. Based on the ideal gas law the volumetric storage density of hydrogen at ambient temperature (25°C) can be approximated utilizing $0.0807P$ where P is pressure in bar [119]. Thus, at a pressure of 350 bar, its volumetric density would be approximately 28 kg/m^3 without taking the compressibility factor into consideration. In comparison, methanol is a liquid with a density of 792 kg/m^3 at 1 bar and 20°C. The volumetric density attained is also much lower than that of liquid hydrogen (70.8 kg/m^3 for liquid hydrogen at atmospheric pressure vs $<40 \text{ kg/m}^3$ for gaseous hydrogen at 800 bar) [112]. Therefore, storing hydrogen in an economically viable manner requires it to be either (i) compressed, (ii) liquified or (iii) stored in a binding material (chemical or metal hydride) as shown in Figure 8.

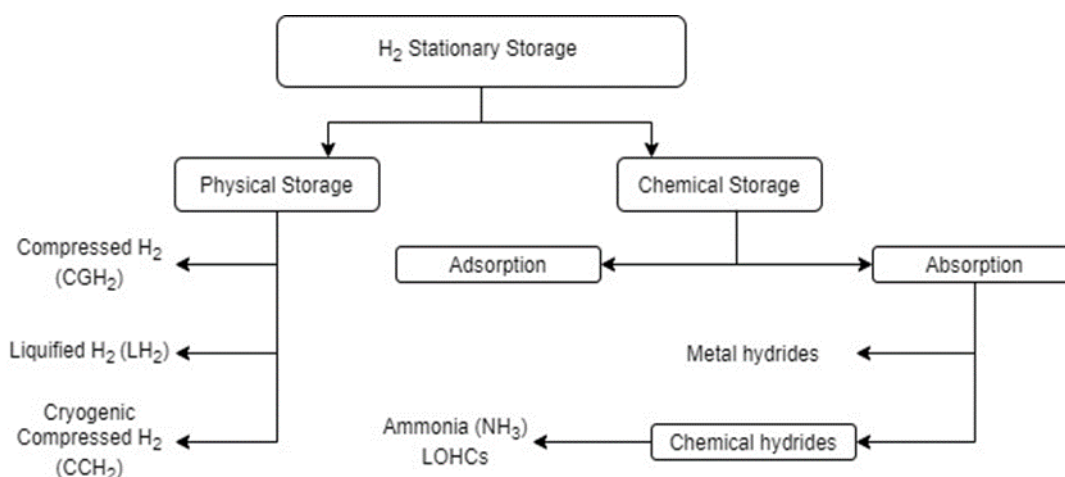


Figure 8: The main forms of hydrogen storage

The most prevalent method employed is storing compressed gaseous hydrogen (CGH₂) ranging from 350-900 bar in pressurized vessels or tanks [119]. The optimal storage pressure depends on the storage vessel material and on the compression efficiency. Steel vessels were commonly used for CGH₂, although as eluded to earlier, hydrogen tends to diffuse into steel and cause embrittlement failure, especially after frequent charging and discharging. This problem has now been solved by utilizing vessels of composite materials (sometimes reinforced with concrete). Although this increases the capital and operational costs of the technology it ensures longer technical life for the vessels.

Because hydrogen molecules have a low molar mass and small size, the gas can diffuse through materials that are considered impervious to most gases. Thus, the likelihood of gas leakage associated to hydrogen is higher [120]. This problem is particularly applicable for transporting hydrogen in long distance pipelines with several valves and compressor stations and it is also relevant to steel pressure vessels which will require additional sealing or multibarrier containment to prevent leakage. Moreover, its low vapor density and high buoyancy combined with its colourless and odourless nature complicates its detection, especially outdoors, and increases the chances of gas accumulation at high points [121]. Its low flame temperature also poses as a risk if hydrogen leaks from storage containers as the likelihood of explosion is high. Table 3 summarizes the differences between hydrogen and methane characteristics that highlight handling complications associated to hydrogen.

Liquefying hydrogen (1.1013 bar, -253 °C) or cryogenically compressing hydrogen (300 bar, -253 °C) results in a higher energy density than gaseous hydrogen. It can be cost effective when transporting hydrogen over long distances however it is 64% more energy intensive than compression [3]. Additionally, producing LH₂ has a parasitic load consuming 30%-40% of the energy content of the hydrogen stored on an LHV basis (depending on the size of the liquefaction plant) [122]. Another drawback of LH₂ is the unavoidable boil-off rate. Estimated boil-off losses from a LH₂ tanker to a stationary vessel are 15% of LH₂ delivered (by mass) for 100 kg/day capacity, 5% for 400 kg/day, and less than 2% for higher than 1,800 kg/day capacity [123]. This occurs because liquid hydrogen is stored as a cryogenic liquid that is at its boiling point. Any heat transfer during transportation or shifting the liquid will result in a small amount of evaporation. Other storage solutions such as cryogenic compression, chemisorption of hydrogen by metal hydrides or liquid organic hydrogen carriers are outside the scope of this study [4].

Table 3: Physical properties of hydrogen vs methane relevant to storage risks [120], [124]

Property	Hydrogen (H ₂)	Methane (CH ₄)
Vapor Density (kg/m ³)	0.08	0.65
Boiling point (°C)	-253	-165
Colour and Odour	No colour and odourless	Orange or yellow, can be odorized
Chemical reactivity	<ul style="list-style-type: none"> • Explosive when reacting with oxygen • Sabatier reaction with free carbon to form methane and reactivity with Na, K, Ca and U 	Non-reactive as a gas for the most part
Flame Temperature (°C)	2.04	1,875

6. Feasibility of large-scale hydrogen storage technologies

This section will aim to present an analysis of large-scale hydrogen storage options, mainly geological storage, and their ability to meet the technical parameters for a feasible energy storage. Pressure vessel storage is covered briefly due to its prevalence in commercial applications.

The most feasible form of storing hydrogen on a large scale is still unclear, The most appropriate method is dependent on a range of factors such as the purity of hydrogen required, the response time of hydrogen release, and other constraints regarding pressure and temperature requirements.

There are several important non-cost related parameters to consider when assessing the feasibility of hydrogen storage technology. These include:

- Ability to retain hydrogen for long periods of time (low leak risk)
- Purity of hydrogen stored
- Ability to withstand fluctuations due to intermittent power
- Damage to environment

6.1. Pressurized Vessels

There are four main types of pressure vessels currently utilized for bulk storage of hydrogen. Type I vessels are all metal cylinders usually made from carbon steel or low alloy steel [125]. Commonly utilized in industrial and commercial applications, they are a cheap, mature technology, however the vessels are inherently heavy. Hydrogen is usually stored at 200-300 bar with a maximum limit of 500 bar [28]. The main problem with conventional tanks for high pressure hydrogen storage is the cracking and blistering of steel making it less ductile, especially after multiple charging and discharging cycles [126].

Type II vessels were developed as a lighter, more durable alternative to type I vessels and they can withstand a similar amount of pressure [15]. This is due to a load-bearing metal liner hoop around the main cylindrical body which is also partially wrapped with a resin-impregnated filament [125]. This increases the tightness, given the high rate of diffusivity of hydrogen and reinforces the vessel by spreading the structural load across both the liner and composite material. Thus, it increases the maximum stress the vessel can withstand before tensile strength is reached. As a result, the gravimetric storage capacity of these vessels is higher, 2.1% by mass vs 1.7% by mass for type I [127].

Type III vessels are more expensive than the latter two and are fully wrapped with a low-load-bearing metal liner and a high-strength composite liner [28]. This type of vessel has a maximum operating pressure of 450 bar. Type IV vessels are the most expensive, the most lightweight, and can withstand pressures of 700 bar (maximum 1000 bar), achieving a gravimetric storage capacity of 5.7% by mass [127]. These vessels consist of a polymer liner that is wrapped with

a fiber resin composite. Type V vessels are liner-less fully composite vessels, are lighter than the composite vessels already mentioned however they are still in development and currently very expensive [128].

These pressure vessels have the advantage of being built near the hydrogen production facility and thus reduce transportation costs. They also retain the purity of hydrogen over time, although they will be infeasible for the large-scale storage of hydrogen due to the sheer material cost associated to the quantity of vessels that would be required to meet the hydrogen demand on a TWh-scale. High land area requirement is another factor decreasing the competitiveness of pressure vessels, given the scarcity and cost of land. Table 4 compares the material and cost characteristics of pressure vessel storage.

Table 4: Characteristics of Type I- Type IV pressure vessels, [28], [125]

Type	Cost	Metallic part failure	Polymer part failure	Composite part failure	Maximum pressure	Gravimetric density	Application
I	-	Hydrogen embrittlement or premature fatigue	N/A	Fibre breaks, delamination and matrix cracking due to unexpected impact or high-pressure load	≤ 500 bar	-	Stationary
II	+				Unlimited	+	Stationary
III	++		≤ 450 bar		++	Industry & mobility	
IV	+++		Hydrogen dissolution in polymer matrix, deformation due to quick discharging and charging		≤ 1000 bar	+++	Industry & mobility

6.2. Geological Storage

Geological storage of compressed gaseous hydrogen in underground reservoirs has been identified as the cheapest and safest solution that can provide the large scale and low costs pertinent for seasonal storage.

Underground gas storage (UGS) is a state-of-the-art technology that has been utilized for storing natural gas in geological formations for several decades. It is unparalleled in its ability to store enormous volumes of gas (upwards of 500,000m³) at a fairly high pressure (200-300 bar). These features make it one of the most economical forms of storing large amounts of energy and it is perhaps the cheapest form of storing hydrogen at the scale required for seasonal energy storage [4], [129]. Underground hydrogen storage (UHS) follows the same principle as UGS. Compressed hydrogen is injected into underground reservoirs through injection wells to a significant depth (400–2000m) and consequently withdrawn through withdrawal wells.

There is usually a confining layer in between the reservoir and the surface. UHS systems also include above ground compression, purification equipment and pipeline storage depending on the end use application and the quality of hydrogen stored [128].

Specifically, for seasonal storage, the UHS must have the ability to retain the purity of hydrogen for longer periods of time and contain it for long durations i.e. they must withstand fluctuating stress fields caused by repeated injection cycles. A huge advantage offered by subsurface storage areas is that they are enclosed by several hundred meters of rock and thus have minimal impact on land usage and the building of urban infrastructure nearby as compared to surface storage.

The main limitation is that most sites are highly dependent on geographical availability and the type of terrain available. In addition to this, researchers are still assessing the feasibility of storing renewable hydrogen in these types of media as compared to natural gas, which has historically been stored in geological storage due to the possibility of (i) hydrogen triggering growth of consuming microbes, (ii) repeated injection and withdrawal compromising structural integrity, (iii) possibility of hydrogen reacting with unknown minerals [130].

Underground reservoir capacity is divided into cushion gas and working gas. Cushion gas is defined as the minimum amount of gas required to maintain adequate pressure within the reservoir to enable efficient injection and to prevent water intrusion [131]. It acts as a buffer and is non recoverable, so it incurs a significant part of the capital cost of the reservoir. It does not affect the deliverability rating of the reservoir however the amount of cushion gas plays a factor in choosing reservoirs for peaking or baseload storage [132]. The working gas capacity of the reservoir is the maximum amount of gas that can be injected and withdrawn from the reservoir repeatedly.

The main types of UHS are:

- Salt caverns
- Depleted oil & natural gas reservoirs
- Natural saline aquifers
- Hard rock caverns

The primary distinction between the formations mentioned above is whether they are porous media storage, or they are artificially engineered cavities constructed with a specific geometry to achieve a specific capacity. **Saline aquifers** and **depleted hydrocarbon reservoirs** are categorized as porous media storage. The working principle is that injected hydrogen displaces the *in-situ* fluid in the reservoir e.g. brine or residual hydrocarbon. Thus, these usually require sedimentary rocks such as sandstone or limestone which have a high intergranular porosity (energy storage capacity) and high permeability (injection ability) [24]. These types of reservoirs also have a caprock present above the permeable layer of rock in which specific water capillary action provides enough pressure that seals the reservoir [133]. There is also a trap structure to prevent gas leakage laterally [130].

Conversely, engineered cavities such as **rock caverns** or **salt caverns** are built by making large open cavities deep underground. The rock formations around these cavities continuously apply pressure on them, thus the cushion gas requirement is directly related to the geomechanically required minimum pressure to prevent the structures from buckling. Furthermore, they require rocks with low porosity and permeability to limit the spread of the gas to the external environment e.g. unfractured igneous and metamorphic rocks [24].

The main drawbacks of geological storage are:

- Not all regions have topography required for UHS. Prospective sites are required to be evaluated extensively for storage potential and their ability to meet certain geological and safety standards. Although the exploration activities, regulation and requirement depend on the type of UHS, the basic screening processes includes verifying an adequate reservoir seal, low risk of leakage into soil and ground water and low microbiological and chemical activity [134].
- Bottlenecks created by lack of legal permission to utilize land and maintaining ample distance from lakes, shoreline or sensitive features that risk being contaminated.
- Inadequate natural structural components that require reinforcing and high requirements for cushion gas.

6.2.1. Depleted Oil & Gas Reservoirs

Depleted oil & gas fields are the most common type of subsurface storage, accounting for 74% of the potential UHS sites worldwide [135]. They have an economic advantage over other porous media storage because less resources are utilized for geological exploration efforts. The tightness of these storage formations is also proven as a result of hosting oil and gas for a millennium, currently 81% of natural gas stored underground is in depleted oil & gas fields [136]. This also makes them a very strong contender for SNG storage.

Furthermore, they are well suited for seasonal storage since a maximum of two cycles of injection and withdrawal a year is recommended [137]. The basic structure includes a geological trap at depths of 500-2000 m where either oil or gas was sealed with a layer of impervious caprock above and an aquifer layer below it for support. In depleted gas fields residual gas present in the reservoir can be utilized for cushion gas, meaning less working gas is required as a buffer. Despite this, the proportion of cushion gas can be as high as 40%–50%, much higher than for salt caverns [25]. This can be attributed to their wide and elongated structures and larger volumes (working gas volumes can range from 1 million m³ to several billion m³) [138], [139].

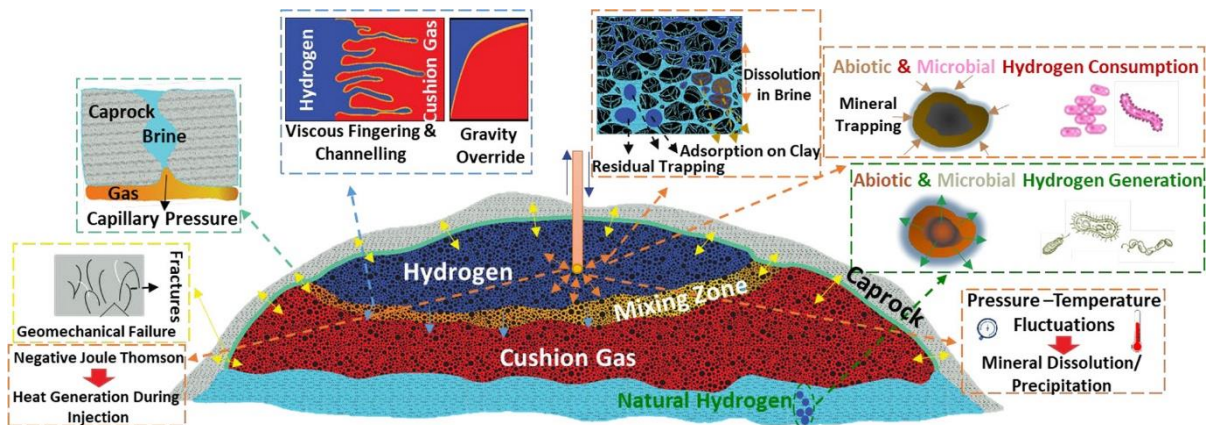


Figure 9: Overview of different geochemical, microbiological and physical processes leading to loss of hydrogen within UGS [141]

These types of storage formations also offer the advantage of offshore storage which is publicly more accepted. One example is the Rough Gas Storage Facility (RGSF) in Southern North Sea (near Yorkshire, England), which has a natural gas storage capacity of around 40 TWh [140]. There are no successful commercial cases of hydrogen being stored in depleted oil and gas fields reservoirs due to the presence of residual hydrocarbons and microorganisms that reduce the purity of stored hydrogen. Studies have shown undesirable reactivity between hydrogen and residual oil in depleted oil fields causing hydrogen dissolution in the oil.

Unwanted microbiological and chemical reactions with residual gas in depleted gas fields is also a cause of concern [129]. To be specific, methanogenic and sulphate reducing bacteria which feed on hydrogen and, if the thermodynamic characteristics of the reservoir allow, convert it to hydrogen sulphide (H_2S) through sulfurization or CH_4 through the Sabatier reaction [25]. Homoacetogenic bacteria (anaerobic microorganisms) are also present in some formations and can cause clogging by producing acetate [130]. Moreover, hydrogen has a negative Joule–Thomson coefficient and very high thermal conductivity which could further exacerbate these reactions with the temperature variation near the injection well [141]. Mineral dissolution may also occur due to changing pressure in the reservoir during injection cycles, affecting the structural integrity of the caprock. Hydrogen loss through viscous fingering could occur through which hydrogen mingles with the cushion gas due to its low viscosity [142]. Figure 9 presents the different geochemical and biological processes that could lead to the contamination or loss of hydrogen within depleted oil & gas reservoirs.

Another complication associated the technology is material incompatibility of the existing infrastructure with hydrogen. Structures such as injection wells on site are, upon contact with pure hydrogen, at risk of corrosion, placing the tightness of the storage at risk. There are a few projects that are researching these issues [143]. Overall, depleted oil and gas reservoirs are not yet a feasible option for storing hydrogen over long periods of time. However, if a formal framework for risk-assessment and technical evaluation were created, it would encourage further research in feasibility of such gas storage.

6.2.2. Aquifer Storage

Aquifers are natural porous formations that usually hold groundwater. In order to be utilized for subsurface gas storage the aquifer must have a dome-like geometry that allows the water to be pushed sideways and downwards when displaced by the working gas as well as an impermeable layer over and under the reservoir acting as a seal. Characteristically the permeability of the aquifer directly affects the charging and discharging time of the storage. It is usually included in flow rate calculations as a proportionality factor between the velocity of the working gas and the pressure gradient causing said flow [144]. Due to the porosity of these reservoirs, extensive geophysical experimentation is required to ascertain their tightness. This makes them more capital expensive as compared to depleted hydrocarbon reservoirs. Moreover, conclusive measurements of permeability are only possible at a specific number of places since rapid permeability changes are possible over small distances [25].

Like depleted oil and gas reservoirs, there are no cases of pure hydrogen being stored in aquifers. The closest experience is the storage of town gas (50%-60% hydrogen) in a saline aquifer (385 million m³ capacity) by Gaz de France between 1956 and 1972 in Beynes, used for regulating fluctuations in gas production and demand [145]. However, intensive bacterial activity and contamination of the gas was observed during the storage time which could cause blockages in the fine rock pore spaces. Finally, aquifer storage also suffers from a higher risk of leakage due to the high permeability of the rocks which could lead to diffusion and fingering of hydrogen into water-bearing units [27].

6.2.3. Salt Cavern Storage

Salt caverns are artificially mined cavities created within salt domes or bedded salt deposits through salt leaching. The leaching phase begins by drilling a hole (diameter <1m) into the ground. The needed depth depends on the storage volume and site-specific geographical characteristics. A series of pipes, reinforced by cement are inserted into the hole through which warm water is pumped, dissolving the surrounding salt. The brine collected at the bottom or 'sump' is then pumped up. The brine is then displaced by working gas; in order to insert a pipe system capable of injecting and withdrawing of the gas an explosive charge is detonated to destroy the former pipe installation [118].

Salt caverns are considered the most suitable form of UHS due to the gas tightness provided by the inert salt lining of the cavern, the relatively large volumes that can be attained (typical geometrical volumes of 100,000 m³ to a maximum of 1,000,000 m³) and high operating pressures of 300 bar [137]. Salt caverns can also reach efficiencies of up to 98% without affecting the purity of hydrogen stored [27]. The inertness of the salt offers a tight, sealed space for hydrogen considering the ease at which hydrogen can escape and its high reactivity, thus preventing any risks to the external environment and leading to the risk of leakage being negligible. Moreover, the working gas to cushion gas ratio is usually 80:20, much higher than other types of UHS [146].

Salt caverns also have high delivery rates as compared to depleted reservoirs and aquifers due to low permeability of rock (but not to the extent of risk of leakage as in aquifers)[27]. The operating pressure in salt caverns is governed by the salt creep pressure. Due to the depth of salt caverns, the lithostatic pressure around the cavern is high and the rock salt mimics the behaviour of a dense liquid. Salt creep occurs when the pressure inside the cavern is lower than the lithostatic pressure and causes the cavern shape to morph and converge inwards. This decrease in cavern volume can also lead to surface subsidence, damaging above ground infrastructure. The risk of cavern convergence is higher when utilized intermittently for energy storage, thus it is vital to monitor cavern pressure constantly [147].

Hydrogen has already been successfully stored in salt caverns, however in only few locations in the US and in the UK, which have the most geological potential. The Clemens site in Texas has a storage size of 580,000 m³ (900 m depth), the Moss Bluff site, also in Texas has a storage size of 560,000 m³ (800 m depth) and the plant in Teeside, UK, has three caverns with a volume of 70,000 m³ each (350 m depth and 50 bar) [148]. On the USA sites the hydrogen is utilized by the petrochemical industry and in the UK, it is utilized for ammonia and methanol production.

6.2.4. Lined Rock Cavern Storage

Rock caverns are excavated underground facilities that are built in areas with hard rock (igneous or metamorphic) such as Scandinavia, which lack salt domes or porous rocks. In the past, rock caverns have been utilized to host liquid hydrocarbons and gas tightness in the reservoir is provided by hydrostatic pressure of ground water over the mined cavity. Given the permeability of hydrogen, these formations do not have the desired level of imperviousness. However, a recent development in rock cavern storage – the concept of lined rock cavern storage (LRC), would be far more suitable.

It involves implementing gas tightness by encasing a rock cavern with a lining that has three main components: a sheet of stainless steel to contain the gas, a concrete layer between the steel and the surrounding rock and the rock mass which absorbs the load from the working gas pressure [10]. The purpose of the concrete is to ease the pressure load on the liner and transfer the load smoothly to the surrounding host rock. The lining itself should not be carrying a significant amount of load but should be able to sustain the small elastic and plastic deformation due to the working gas pressure [139].

The first LRC facility was built in Skallen, Sweden, in 2004 to store natural gas. It can withstand a pressure range of 20-200 bar, translating to a capacity of approximately 740 t of hydrogen [32]. The storage is 51 m high and 35 m in diameter with a volume of 40,000 m³. The working gas capacity is approximately 90% and the cushion gas is 10% [10]. This facility was utilized as the basis of a pre-feasibility study for constructing a pure hydrogen LRC storage for HYBRIT (Hydrogen Breakthrough Ironmaking Technology), a joint initiative of SSAB, LKAB and Vattenfall with the aim of developing the world's first fossil-free steel.

Through this study it was found that conventional low-alloyed ductile carbon steel would degrade as a result of hydrogen embrittlement and the most suitable steel would be austenitic stainless steel however, more mechanical testing is required to confirm the results. Additionally, after the publishing of this feasibility study, construction of a pilot LRC facility had commenced in Lulea in 2020 to support the HYBRIT initiative. The 100m³ facility is being built 30 m underground with an estimated investment cost of over 25 million euros. It is expected to be operational from 2022 [149].

In terms of its feasibility for storage, an LRC offers more gas tightness as compared to the options discussed above and has similar deliverability characteristics as salt caverns i.e. gas can be withdrawn over multiple cycles and at high rates [27].

7. Methodology

This chapter describes the methodology utilised for assessing the economic feasibility of hydrogen for large scale storage as opposed to methane, methanol and ammonia by developing a LCOS model on Microsoft Excel. Prior to developing the LCOS model, the CGH₂ technologies with the most technical potential to meet seasonal energy storage requirements are decided based on the findings from the previous section.

Table 5 provides a comparative assessment of geological storage options referring to the most important parameters for a feasible large-scale hydrogen storage. Salt cavern storage and LRC storage hold the most potential because they not only perform well in terms of meeting the criteria mentioned within the table, but they also meet seasonal storage requirements.

Type I-IV pressure vessel storage technologies are included within the analysis since they are the most common form of stationary storage for energy applications within the industry today.

The overall workflow of the model development is presented in Figure 10. The inputs define the fuel energy storage requirement and the amount of fuel required for compression. Techno-economic characteristics of CGH₂ stored within salt caverns, LRC and type I-IV pressure vessels and similar data for standard industrial storage of the other carbon neutral fuels is collected for creating the storage model. The compression model is designed based on an isentropic reciprocating compressor. The type of compressor is assumed to be the same for each fuel.

Table 5: Feasibility of geological storage of H₂

Storage Characteristics	Lined Rock Cavern (LRC)	Salt Caverns	Depleted Oil & Gas Reservoirs	Aquifer Storage
Description	Excavated rock cavern, lined with steel and reinforced with concrete	Solution mined cavities within salt domes or bedded salts, formed by leaching salt	Gas/oil in existing reservoir is displaced utilizing working gas	Ground water bearing reservoirs
Operating pressure (bar)	20-200	Up to 275	200	Up to 200
Injection cycles	Multiple (more than 3) cycles a year, high deliverability	Multiple (more than 3) cycles a year, high deliverability	Suitable for 1-2 cycles a year, low deliverability	Suitable for 1-2 cycles, low deliverability
Maximum volume (m³)	Up to 200,000 (Hard rock)	Up to 1,000,000	Up to 500,000	Up to 10 ⁹ m ³ for NG
Leakage tendency	Lack of data	Negligible due to inertness of salt	Hydrogen loss through conversion	High risk due to permeability of porous rock
Undesirable characteristics	Intensive capital costs, no commercial cases	Severely limited by geographical availability	Methanogenic and sulphate reducing bacteria	Very permeable, contamination of ground water, geographically limited
Cushion gas requirement	10%	20%-30%	50%-60%	80%
Commercial cases	Lulea to support HYBRIT, Skallen (NG for pre-feasibility analysis)	Teesside, Great Britain, Clemens Dome, Texas, Moss Bluff, Texas – all for petrochemical factories	None	None, only town gas of 50%-60% H ₂ in 1956, France

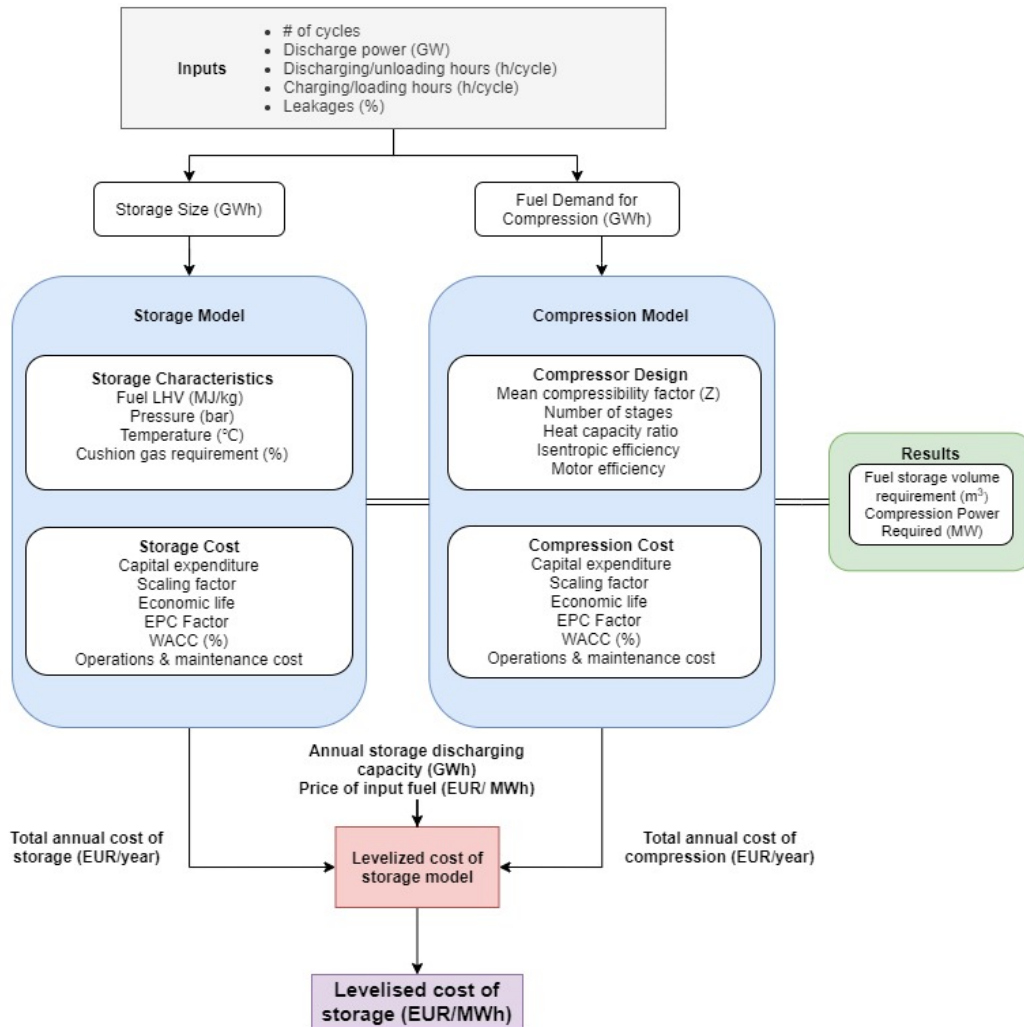


Figure 10: Overview of the methodology

The storage model calculates the volume of fuel required to meet the energy storage demand defined within the inputs and the total annual cost of storing the fuel. The compression model calculates the compression power required to and total annual cost to compress the fuel to the designated storage pressure.

Finally, the LCOS model utilizes the costs, the annual discharging capacity of the energy storage (energy provided) and the price of the input fuel to calculate the LCOS of each fuel within each storage type. This indicator was chosen because it allows a fair comparison between different types of storage technologies, which is required to achieve the objective of this study.

A short sensitivity analysis is carried out to identify which inputs or cost parameters have the most impact on the final LCOS values. Eight different pathways were analysed as presented in Figure 11.

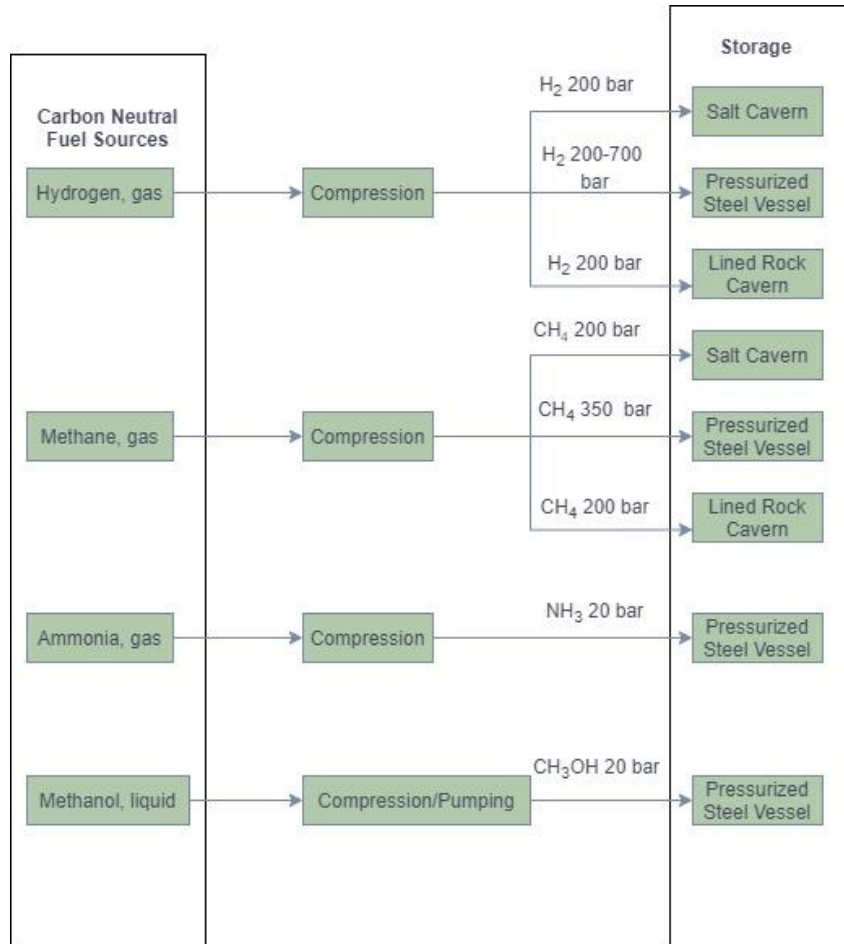


Figure 11: Storage and fuel types modelled for LCOS

7.1. Model set-up

This section presents the scenarios and the inputs defined to create the storage and compression models in this thesis.

The basic principle of the model is that storage is carried out in two phases:

- Phase 1: Fuel is compressed to a certain pressure prior to storage. The **compression model** calculates the compression capacity required depending on the energy storage requirement and computes the associated costs (\$M).
- Phase 2: Fuel is stored in the specified storage technologies for a predefined period. The **storage model** calculates the *capacity of energy storage* (m³ or kg) required depending on the energy storage requirement and computes the associated costs.

The process of decompressing fuel to a desired pressure for end use was assumed to be negligible and was not considered in the analysis.

7.1.1. Cases

The cases defined differentiate between the method of utilization for storage. Three cases are considered, as mentioned in Table 6 . In case A the storage is utilized on as seasonal storage such that it will only have one loading cycle in a year and will be discharged over a period of months. In case B the storage is utilized weekly (discharged over half a week) and in case C the storage is utilized daily. These cases help identify the cost of storage depending on its end use application. The seasonal storage could be utilised for grid-scale energy storage, the weekly storage could most likely be utilized for industrial purposes and the daily storage (due to its small scale) could be utilized for a community or pilot-scale project.

Table 6: Description of scenarios and storage cycles

Case	Storage Type	Loading Cycles (#/yr)	Loading hours (h/cycle)	Unloading hours (h/cycle)	Discharge demand (GW)
A	Seasonal	1	4380	3504	14
B	Weekly	52	84	67	0.14
C	Daily	365	12	10	0.10

7.1.2. Inputs and assumptions

The starting point for the modelling process is defining the energy storage requirement for each case. The parameters below are defined by the user to calculate this requirement:

- Number of cycles in a year
- Discharge power demand of storage i.e. power provided over one full cycle
- Loading hours per storage cycle
- Unloading hours per storage cycle

The main assumptions for these parameters are:

- The storage will be loading **50%** of the entire cycle and unloading **40%** with idle time in between e.g. 50% and 40% of 8760 for Case A will mean the storage discharges over a 6-month period, charges over a 4-month period and is idle for 2 months.
- The discharge demand for seasonal, weekly and daily storage is **14 GW**, **140 MW** and **100 MW** respectively. The user is able to edit these values however these values were chosen based on the expected demand of grid-scale and project-level storage from internal energy system modelling. Table 6 provides the cycle duration of each case and the discharge demand chosen.
- There is no discharge efficiency associated with compression.

These values are utilized to calculate the energy storage requirement, E_s (GWh_{fu}) needed to meet this discharge demand (for one full cycle):

$$E_s = \frac{P_d \cdot t_{un}}{1 - leak_s} \quad (2)$$

Where P_d (GW) is the discharge demand, t_{un} (h/cycle) is the unloading hours per cycle and $leak_s$ (%) is the leakage rate of each hydrogen storage technology. For hydrogen storage, it is assumed to be **1% of the annual energy storage capacity**. Table 7 provides the values of $leak_s$ utilised for each case.

Consequently, the amount of fuel required for compression, E_c (GWh_{fu}) was calculated considering leakages in both stages as:

$$E_c = \frac{E_s \cdot C_{load}}{1 - leak_c} \quad (3)$$

Where C_{load} is the number of loading cycles per year and $leak_c$ (%) is the leakage rate of fuel compression.

For hydrogen, a rate of **0.5% of annual fuel demand for compression** is chosen based on the typical ratings of hydrogen compressor seals as mentioned in the 2020 U.S Department of Energy hydrogen delivery targets [150]. Table 8 provides the values of $leak_c$ utilised for each case. The leakages are scaled appropriately for daily and weekly storage.

At STP conditions, hydrogen has a three times larger diffusion coefficient than methane in pure water [151] and leakage tests implemented on gas distribution systems in the U.S. identified that the volume of hydrogen leakage is three times that of methane. Thus, the leakage rate for the other fuels is assumed to be three times less than the annual rate for hydrogen for both storage and compression [152].

E_s and E_c are then calculated for each case and utilized as inputs for the storage model and compression model as shown by Table 9 and Table 10.

Table 7: Storage annual, weekly and daily leakage rate

Case	Storage leakage rate for 1 unloading cycle
A	0.1%
B	0.0096%
C	0.00137%

Table 8: Compression annual, weekly and daily leakage rate

Case	Compression leakage rate for 1 loading cycle
A	0.5%
B	0.0096%
C	0.00137%

Table 9: Energy storage requirement for each case

Case	Storage Size (GWh _{fu})			
	Hydrogen	Methane	Ammonia	Methanol
A	49,552	49,220	49,220	49,220
B	10	9	9	9
C	0.97	0.96	0.96	0.96

Table 10: Compression fuel demand for each case

Case	Compression Demand (GWh _{fu})			
	Hydrogen	Methane	Ammonia	Methanol
A	49,801	49,302	49,302	49,302
B	496	492	492	492
C	354	352	352	352

7.2. Storage model

From the previous section, the amount of energy that must be stored in each storage technology over one cycle is calculated. This is utilized to calculate the gross volume of the reservoir or pressure vessel using the ideal gas law. This applies to fuels that are gases when compressed, hydrogen and methane. The assumption here is that the gases will behave like ideal gases while stored.

The first step involves calculating the mass of the fuel required to meet E_s utilizing energy density of fuel on an LHV basis:

$$m_{fuel} = \frac{3600}{E_s} \cdot \rho_e \quad (4)$$

Where, m_{fuel} (ton) is the mass of fuel and ρ_e (MJ/kg) is the energy density of fuel.

The energy storage requirement on a molar basis is calculated as:

$$n_{fuel} = \frac{m_{fuel}}{M} \quad (5)$$

Where, n_{fuel} (mol) is the energy stored and M (g/mol) is the molar mass of each fuel. This yields the amount of substance needed in evaluating the gross volume need to meet E_s as per:

$$V_{gross} = \frac{n \cdot R \cdot T}{P} \quad (6)$$

Where, V_{gross} (m³) is the storage volume, P (Pa) is the operating pressure of the storage type, R (Jmol⁻¹ K⁻¹) is the gas constant and T (K) is the temperature in the storage. The operating characteristics of each storage type utilized for this calculation are provided in Table 11 . The operating temperature is assumed to be ambient i.e. 300 K. In reality, methanol is most likely stored in close to ambient pressure, but pressurizing it takes into consideration any electricity need for pumping.

Table 11: Operating pressure of each storage type

Storage Type	Operating Pressure (bar)
H ₂ , CH ₄ - Salt Cavern	200
H ₂ , CH ₄ - LRC	200
H ₂ -Type I vessel	200
H ₂ -Type II vessel	500
H ₂ -Type III vessel	450
H ₂ -Type IV vessel	700
CH ₄ pressure vessel	350
NH ₃ pressure vessel	20
CH ₃ OH pressure vessel	20

For pressure vessel storage, V_{gross} is the total volume of storage required to meet the energy storage requirement. The utilized volume, V_{net} was obtained by multiplying V_{gross} with the cushion gas ratio, Cg , for geological storage. Table 12 provides the cushion gas ratio for salt cavern storage and LRC storage.

$$V_{net} = V_{gross} \cdot Cg \quad (7)$$

Table 12: Cushion gas ratio

Reservoir Type	Cushion ratio (Cg)
LRC	0.1
Salt cavern	0.4

V_{net} and V_{gross} are utilized to calculate the CAPEX and OPEX of each storage system based on reference costs and storage sizes found within literature.

The calculation of V_{gross} for ammonia and methanol is carried out using a simple density calculation:

$$V_{gross} = \frac{m_{fuel}}{\rho_e} \quad (8)$$

7.3. Compression Model

In order to calculate the compression equipment capacity required, $P_{designc}$ (MW), the theoretical (ideal) power requirement, P_{idealc} (MW) is calculated assuming an isentropic (adiabatic and reversible) reciprocating compressor since it is the most common for high compression ratio applications. It is assumed that the compressor has no friction or internal leakage and is well insulated. The input fuel power required for compression is calculated as:

$$P_{in} = \frac{E_c}{t_l} \quad (9)$$

Where P_{in} (GW) is the input fuel power, and t_l (h/cycle) is the number of loading hours per cycle.

This is utilized to calculate the inlet mass flow rate of the compressor [153]:

$$Q_{fuel} = \frac{P_{in}}{\rho_e \cdot 3600} \quad (10)$$

Where Q_{fuel} (kg/h¹) is the mass flow rate. The ideal power requirement P_{idealc} is calculated utilizing a general isentropic compressor power formula [153]:

$$\frac{P_{idealc}}{stage} = \left[\frac{k \cdot Z_a \cdot R \cdot T_{in}}{k - 1} \times \left[\left(\frac{P_2}{P_1} \right)^{(k-1)/k} - 1 \right] \times Q_{fuel} \right] \eta \quad (11)$$

Where, k is the heat capacity ratio ($\frac{C_p}{C_v}$), Z_a is the average gas compressibility factor, T_{in} (K) is the inlet temperature, P_2 (bar) is the outlet pressure and is equal to pressure values in Table 11, P_1 (bar) is the inlet pressure and is assumed to be 20 bar for all fuels, and η is the isentropic efficiency (%).

The actual compressor design capacity $P_{designc}$ is obtained with the motor efficiency and η_{motor} :

$$P_{designc} = \frac{P_{idealc}}{\eta_{motor}} \quad (12)$$

A single stage compression with an isentropic efficiency of 85% and a motor efficiency of 95% is utilized [154]. The gas compressibility factor Z differs depending on the fuel and the pressure of the storage since gases behave differently, especially at higher pressures. At pressures below 35 MPa and atmospheric temperatures of 20–27°C, Z is always greater than unity for hydrogen and less than unity for methane for methane [155].

This implies a larger amount of hydrogen gas will be required than methane gas to meet the same energy requirement. Since the exact temperature conditions within the storages are unknown, for simplification, an average compressibility factor of Z_a has been utilized for both fuels. It is also important to note that the compressibility factor is very sensitive to temperature differences, thus utilizing a tool that calculates the compressibility factor considering all relevant variables would be beneficial for a more in-depth analysis. Table 13 provides the values utilized for hydrogen and methane at different pressures obtained from [156].

Table 13: Compressibility factor at different pressures

Pressure (bar)	Z_a
200 – 350	1.03
< 350	1.30- 1.40

¹ (m³/h) for ammonia and methanol

The compression power calculation for ammonia and methane is similar however the inlet flow rate, V_{fuel} (m^3/h) is calculated utilizing the energy density ρ_e (MJ/kg) and volumetric density, ρ (kg/m^3) as per:

$$V_{fuel} = \frac{P_{in}}{3600 \cdot \rho_e \cdot \rho} \quad (13)$$

The ideal power requirement for compression is calculated by utilizing a formula for pump flow:

$$P_{idealc} = \frac{V_{fuel} \cdot (P_2 - P_1)}{3600} \quad (14)$$

The electricity consumption of the compressor $Elec_c$ ($MWh_{el}/year$) is calculated by:

$$Elec_c = P_{designc} \cdot t_l \quad (15)$$

7.4. Capital and operational expenses

The total system cost on an annual basis is the sum of total annual costs of compression, TC_{comp} ($\$/year$) and storage $TC_{storage}$ ($\$/year$). The total annual cost can be broken down into cost components:

$$TC_{comp} = CAPEX_{compa} + OPEX_{s.energy} + OPEX_{c.non-energy} + TC_{electricity} \quad (16)$$

$$TC_{storage} = CAPEX_{storagea} + OPEX_{s.non-energy} \quad (17)$$

Where, $CAPEX_{compa}$ ($\$/year$) is defined as the annual capital cost of compression equipment including EPC cost, $CAPEX_{storagea}$ ($\$/year$) is defined as the annual capital cost of storage installation including EPC cost, $OPEX_{c.non-energy}$ ($\$/year$) for compression is defined as a 6% of CAPEX [150].

$OPEX_{s,non-energy}$ (\$M/year) for storage is defined as a 4% of CAPEX and $TC_{electricity}$ (\$M/year) is the cost of electricity required to run the compression equipment on design capacity [106].

For simplicity, it is assumed that the storage system does not have an additional electricity requirement for it to perform its function.

The capital and operational costs for each storage technology and the compression equipment are calculated based on reference literature values scaled to the volume or mass of storage and compression power required using a **scaling factor**. After calculating the total cost of installation using this method, an **engineering procurement and construction cost (EPC)** cost and a default **weighted average capital cost (WACC) of 6%** is utilised to calculate the annual cost of storage and compression. Table 14, Table 15 and Table 16 present the financial data and scaling factor estimation obtained from literature for all the fuels.

The capital cost of compression, $CAPEX_{comp}$ (\$M) is calculated as:

$$CAPEX_{comp} = \left(\frac{P_{designc}}{P_{ref}} \right)^{s.f.} \cdot Eq_{cprice} \cdot EPC \quad (18)$$

Where, P_{ref} (kW) is the reference power, $s.f.$ is the scaling factor, and Eq_{cprice} is the reference cost of installation.

The capital cost of storage, $CAPEX_{storage}$ (\$M) is calculated similarly as:

$$CAPEX_{storage} = \left(\frac{V_{gross}}{V_{ref}} \right)^{s.f.} \cdot Eq_{sprice} \cdot EPC \quad (19)$$

Where V_{ref} (m³) is reference storage volume and Eq_{sprice} is the reference cost of installation.

$CAPEX_{compa}$ and $CAPEX_{storagea}$ is calculated utilizing the payment function on Excel.

Table 14: Financial data for hydrogen storage

Hydrogen Storage				
	Equipment price (\$M)	Reference size	Scaling factor	Economical Lifetime (years)
LRC[157]	29	100 m ³	0.50	30
Salt Cavern [158], [159]	23	500,000 m ³	0.28	30
Type I-IV Pressure Vessel [25] [150]	0.039	10 kg	0.90	10

Table 15: Financial data for methane storage

Methane Storage				
	Equipment price (\$M)	Reference size	Scaling exponent	Economical Lifetime (years)
LRC [157]	29	100 m ³	0.50	30
Salt Cavern [158], [159]	23	500,000 m ³	0.28	30
CNG Pressure vessel [160]	0.0029	0.275 m ³	0.90	30

Table 16: Financial data for ammonia and methanol storage

Ammonia Storage				
	Equipment price	Reference size	Scaling exponent	Economical Lifetime (years)
Steel pressure vessel [106]	623 €/ton	33,000,000 kg	0.90	30
Methanol Storage				
Steel pressure vessel [161]	10 €/ton	1700 kg	0.90	30

Compression equipment				
	Equipment price	Reference size	Scaling factor	Economical Lifetime (years)
Compressor [150]	15 \$/MW	10 kW	0.67	10

The total cost of electricity utilized for compression is calculated as per (20) utilizing an electricity price, p_{el} (\$/MWh_{el}) of 35 \$/MWh based on the average electricity prices in Germany in 2020 [162]:

$$TC_{electricity} = p_{el} \cdot Elec_c \cdot C_{load} \quad (20)$$

7.5. Levelized Cost of Storage Model

Prior to calculating the LCOS, the TC_{system} (€/MWh)² is calculated:

$$TC_{system} \left(\frac{\text{€}}{MWh} \right) = \frac{TC_{system} \left(\frac{M\text{€}}{yr} \right)}{E_S(GWh)} \quad (21)$$

Finally, the LCOS is calculated by subtracting the input fuel costs from the total system costs:

$$LCOS \left(\frac{\text{€}}{MWh} \right) = TC_{system} \left(\frac{\text{€}}{MWh} \right) - TC \left(\frac{\text{€}}{MWh} \right) \quad (22)$$

² \$ to EUR currency conversion for all costs

Table 17: Fuel costs

Fuel	Fuel price (€/MWh fuel)
Hydrogen	80
Methane	120
Ammonia	130
Methanol	130

The fuel costs presented in Table 17 are based on internal high-level feasibility analysis, which cannot be disclosed. The procedure involved conducting a similar model development for hydrogen, methane, ammonia and methanol production based on industry CAPEX and OPEX values and the appropriate conversion technologies and efficiencies.

8. Results and discussion

This chapter presents the storage and compression characteristics of each fuel storage followed by the cost breakdown of the costs associated to each and finally the levelized cost of storage for each case.

8.1. Storage Volume

The storage model is used to compute the quantity of fuel, in terms of volume required to meet the energy storage requirement in each case, A, B, and C, considering the operating pressure of the storage technologies and specifically for UHS, the cushion gas requirement. Figure 12 presents the gross volume, V_{gross} , of compressed hydrogen gas (million m^3) required to fulfil a fuel demand of 48,552 GWh_{fu} (14 GW_{el} discharge power demand for 3504 hours). The graph highlights a general trend of a higher operating pressure leading to a lower volume of gas required; the line indicates the operating pressure on the left-hand side axis.

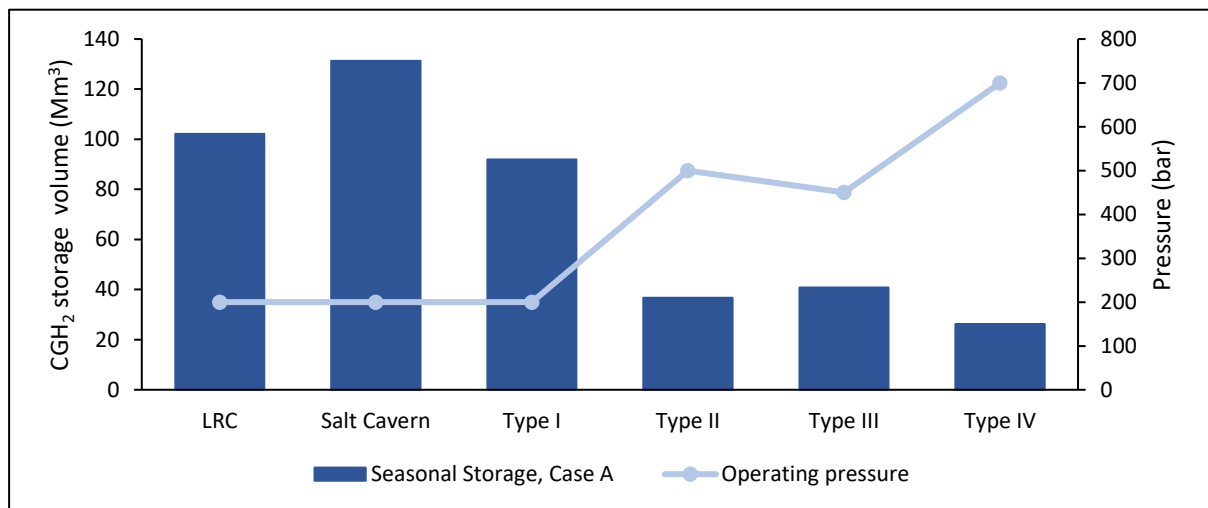


Figure 12: Storage volume and operating characteristics of hydrogen for seasonal storage

The calculation in Figure 12 assumes ambient temperature and ideal gas behaviour from hydrogen. The main difference between the volume required for salt cavern and LRC storage is the higher cushion gas ratio for the former (70% vs 90%) leading to a larger volume of hydrogen required. Figure 13 compares similar storage characteristics for a weekly storage 140 MW_{el} discharge power demand for 67 hours and a slightly smaller daily storage 100 MW_{el} discharge power demand for 10 hours. The trend between the volume of hydrogen and operating characteristics remains the same. It is also important to note that scale of the volume of gas varies significantly when comparing the three cases. On average there is a difference of a factor of 40,000 between case A and case C in terms of the volume of gas required for every storage technology.

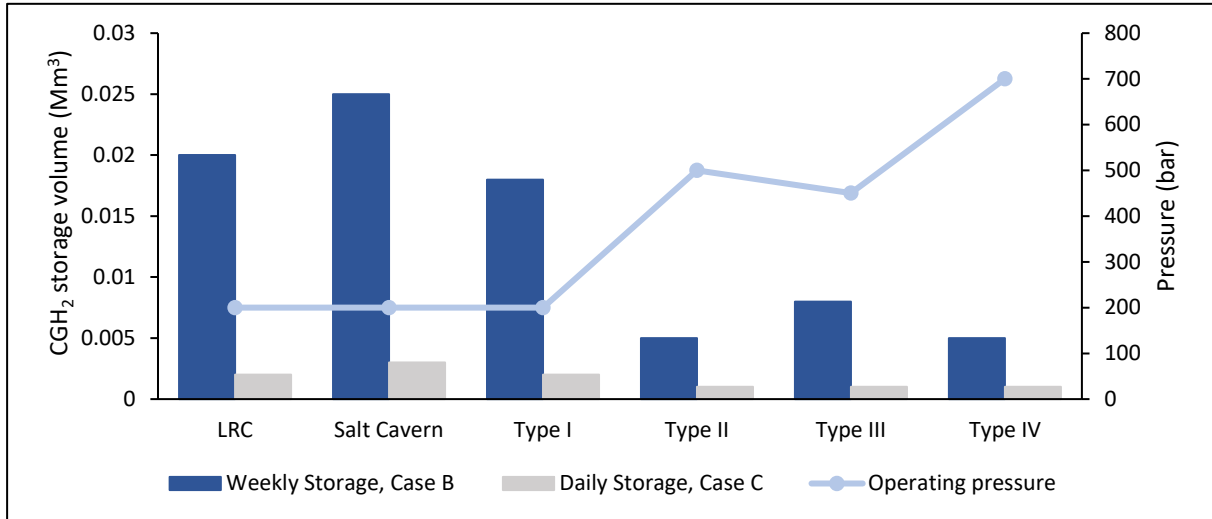


Figure 13: Storage volume and operating characteristics of hydrogen for weekly and daily storage

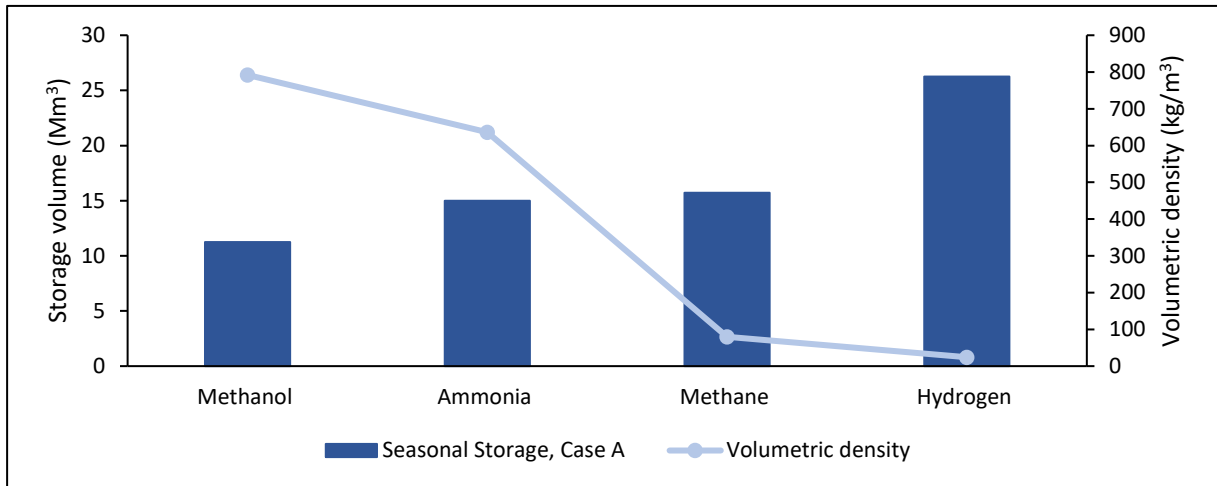


Figure 14: Storage volume vs volumetric density for fuel storage in pressure vessels, Case A. Hydrogen in 700 bar (Type IV), methanol and ammonia in 20 bar steel vessel and methane in 350 bar steel vessel.

It is more beneficial to utilize type I-IV pressure vessel storage for weekly and daily applications. Taking the example of a type IV pressure vessel, if each vessel has a maximum capacity of 100 kg of CGH₂, the reference value utilized for CAPEX calculations, approximately 15,000 units would be required to meet the fuel need for case A. Figure 14 compares the volume of fuel required for pressure vessel storage to volumetric density of each fuel for case A. Due to its superior volumetric density, methanol requires the lowest volume for storage, 11 million m³ at 20 bar. Hydrogen requires 26.5 million m³ at 700 bar which is 81% higher than the volume required for methanol and 50% more than that of methane.

8.2. Compression Energy

The compression model is used to evaluate the compression design capacity, $P_{designc}$ required for each fuel for each case, depending on the storage operating pressure. The factors which affect the compression design capacity are the pressure ratio governed by the pressure at inlet and outlet, the number of stages of compression and the isentropic and motor efficiency. Given the simplified nature of the model there are few parameters that can be varied to analyse the impact on the compression power required.

Table 18 presents the annual demand for compression, E_c , for each case based on the leakage rate associated with each fuel. The input fuel power, P_{in} is calculated utilizing these values and loading cycles in each case i.e. 1, 52 and 365 for case A, B, and C respectively. The input fuel power is approximately 11 GW_{fu} , 6 GW_{fu} , and 29 GW_{fu} for case A, B, and C for all fuels.

Table 18: Annual demand for fuel compression for each case

Annual demand for compression (GWh)	Hydrogen	Methane	Ammonia & Methanol
Seasonal Storage, Case A	49,801	49,302	49,138
Weekly Storage, Case B	491	491	491
Daily Storage, Case C	350	350	350

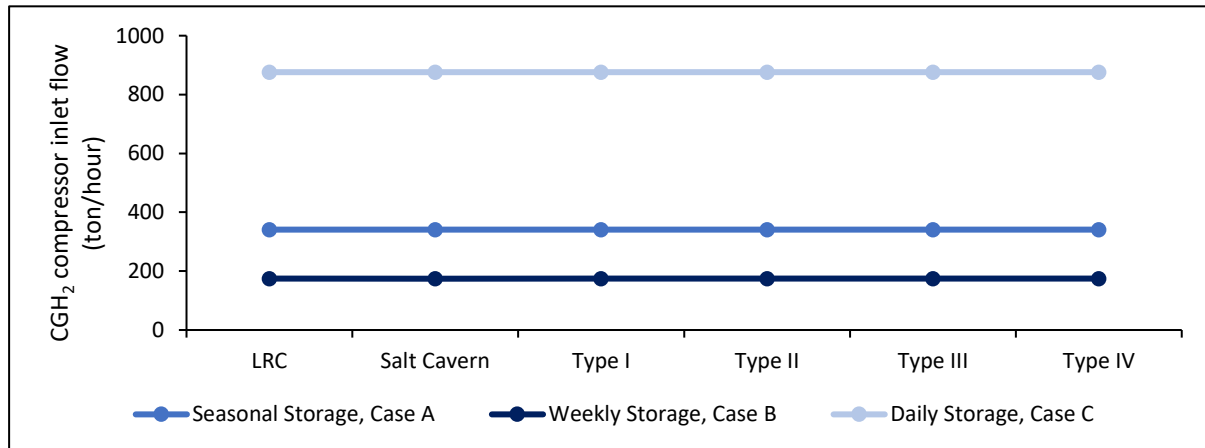


Figure 15: Compressor inlet mass flow for hydrogen for all cases

The compressor inlet flow, Q_{fuel} , is calculated based on P_{in} . **Error! Reference source not found.** shows a comparison of the mass flow rate for each hydrogen storage for all cases, highlighting that daily storage requires the storage to be filled the fastest. E.g. for an LRC, Q_{fuel} is 876 ton/hour compared to 341 ton/hour and 174 ton/hour for weekly and seasonal storage.

Figure 18 presents a comparison of the compression power required for case A, B and C for different hydrogen storage technologies. Three clear trends can be identified: the compression power increases as the operating pressure of the storage technology increases, the compression duration is the shortest for case C, thus compression power is the highest and finally, the compression power for case B is the lowest as a result of the ratio between power requirement (140 MW) and number of annual cycles (52).

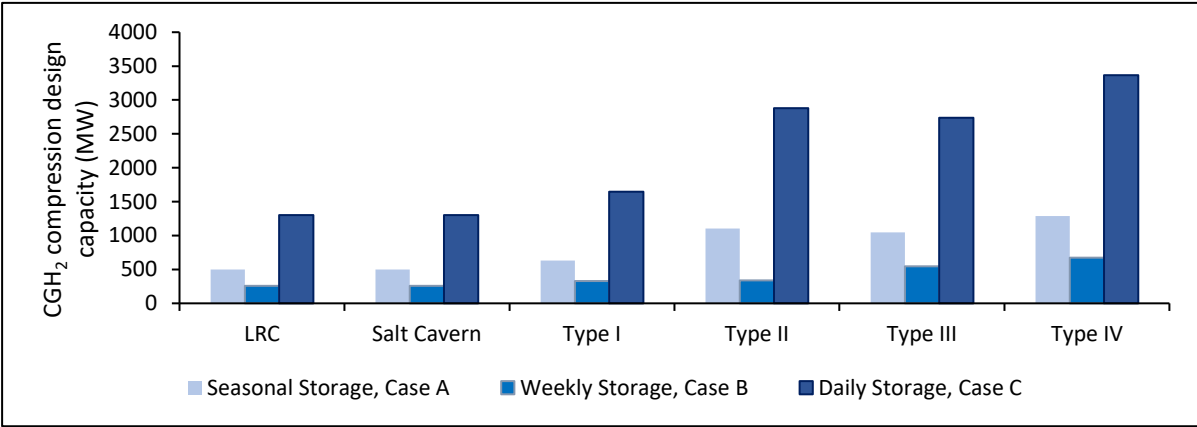


Figure 18: Compression power required for hydrogen storage

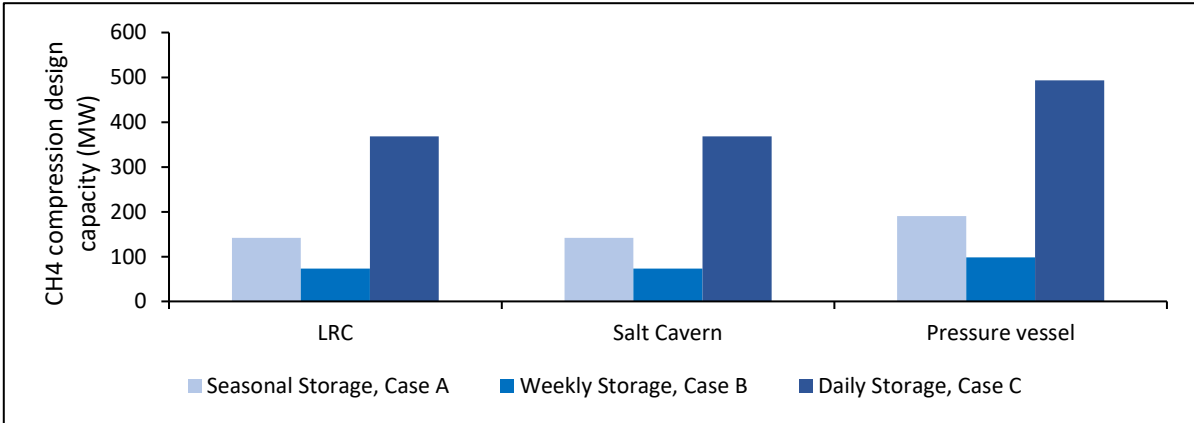


Figure 17: Compression power demand for methane storage

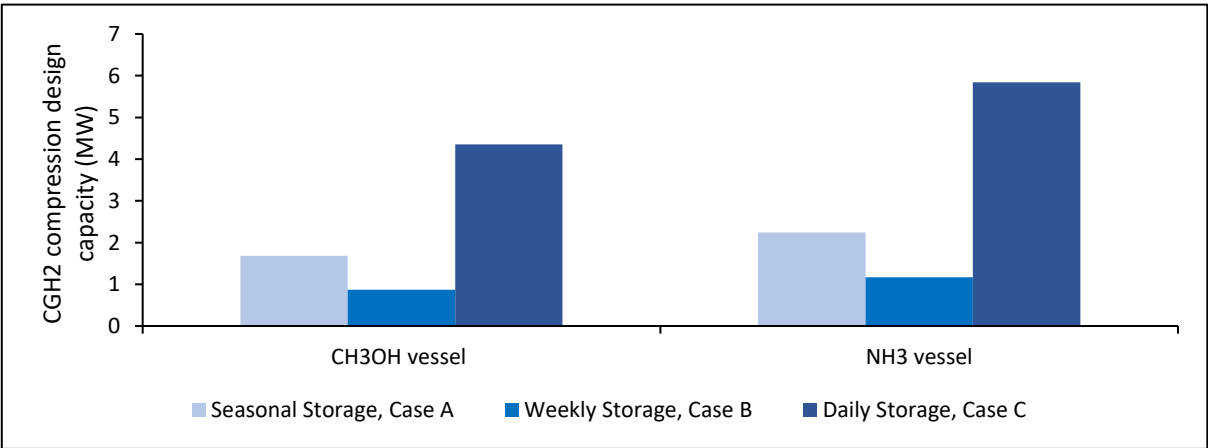


Figure 16: Compression power demand for ammonia and methanol storage

The compression power required for case A, B and C for methane, ammonia and methanol storage follow a similar trend as shown by Figure 17 and Figure 16. Methane storage requires less compression power as opposed to storing hydrogen for all cases. For case A, storing methane in an LRC requires 142 MW_{el} of compression power whereas hydrogen requires 499 MW_{el}. This difference is even greater when comparing compressed hydrogen with a type I pressure vessel (200 bar) to a compressed methane pressure vessel (350 bar). This is mainly due to the low molar mass of hydrogen (2 g/mol) as compared to methane (16 g/mol).

Ammonia and methane require the least compression power of all the fuels owing to their high volumetric density and the low pressure required for liquefaction. The compression power required for methanol and ammonia in a steel pressure vessel at 20 bar is 4.3 MW_{el} and 5.8 MW_{el} compared to 1647 MW_{el} for hydrogen storage in a type I pressure vessel at 200 bar for case C. Thus, low pressure storage is more appealing for daily operations.

As mentioned, there are few factors that can be varied within the model to assess the impact on the compression design capacity however in order to better understand which variables affect the power the most, a sensitivity analysis with respect to the inlet pressure and the compression stages is presented by Table 19. The compression design capacity decreases by increasing the inlet pressure, thus decreasing the pressure ratio, and also by increasing the number of compression stages. This is expected, however, in a real compressor with multistage compression additional cooling power will be needed with each stage. This is not considered in the analysis.

Table 19: Sensitivity analysis of inlet pressure and compression stages on compression design capacity (MW) for hydrogen seasonal storage

Inlet pressure (bar)	Compression stages	LRC	Salt Cavern	Type I	Type II	Type III	Type IV
10	1	727	727	918	1507	1440	1734
15	1	588	588	743	1261	1201	1463
20	1	499	499	631	1103	1048	1289
10	2	572	572	723	1092	1054	1218
15	2	479	479	606	948	912	1067
20	2	417	417	527	851	816	965
10	3	530	530	669	986	955	1090
15	3	449	449	567	866	836	966
20	3	393	393	497	783	754	880

8.3. Economic Analysis

This section will present the cost breakdown for each case and storage technology and compare and analyse the final LCOS values.

8.3.1. Compression and storage annual costs

The total annualized cost of compression comprises of capital expenditure including EPC, electricity and non-energy O&M. Figure 19 and Figure 20 illustrate that the largest cost component of hydrogen compression for all cases is electricity since it is directly related to the input fuel demand i.e. the energy storage profile. Thus, the annual cost of electricity increases as the number of charging and discharging cycles increase in a year. The CAPEX cost component is the lowest in Case C since the capacity of the compression equipment is the smallest which directly affects the cost of installing the equipment. Finally, the non-energy O&M costs have the same share of compression cost for each case since it is assumed to be the same percentage of the CAPEX. All costs are annualized with a WACC of 6%.

The same can be observed when analysing the cost of compression of methane for all cases. This is presented by Figure 22, Figure 21 and Figure 24 however the overall cost of compression is significantly lower as compared to hydrogen. Electricity remains the largest component cost, followed by the CAPEX component for the reasons stated above,

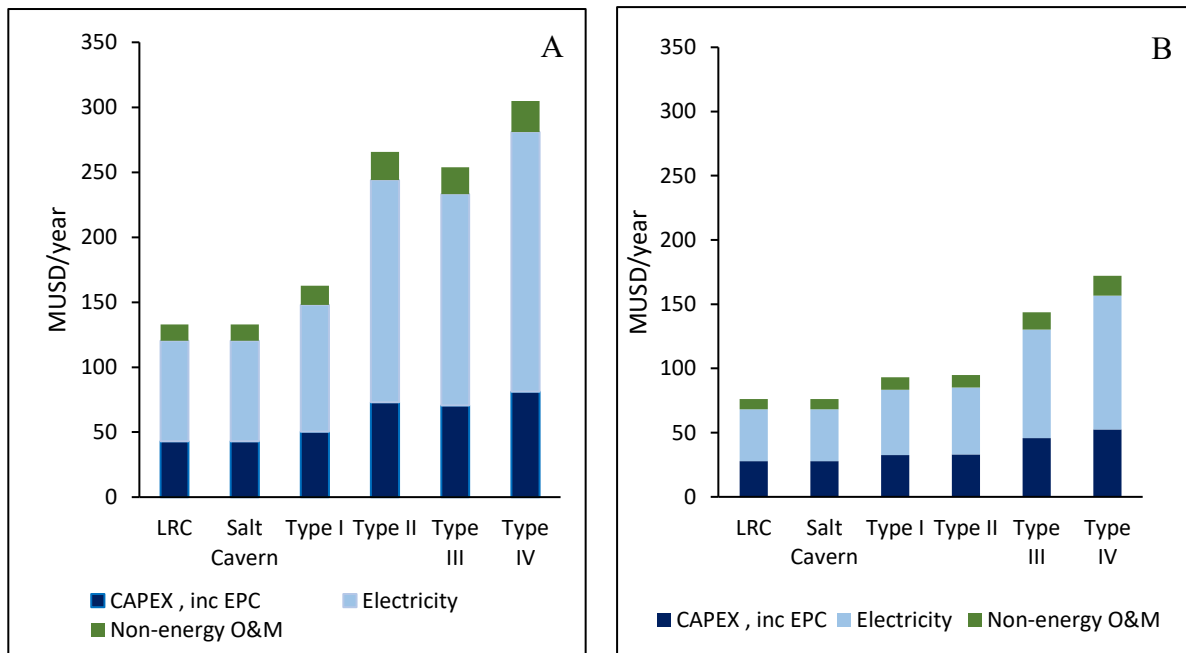


Figure 19: Cost breakdown of hydrogen compression a) Case A b) Case B

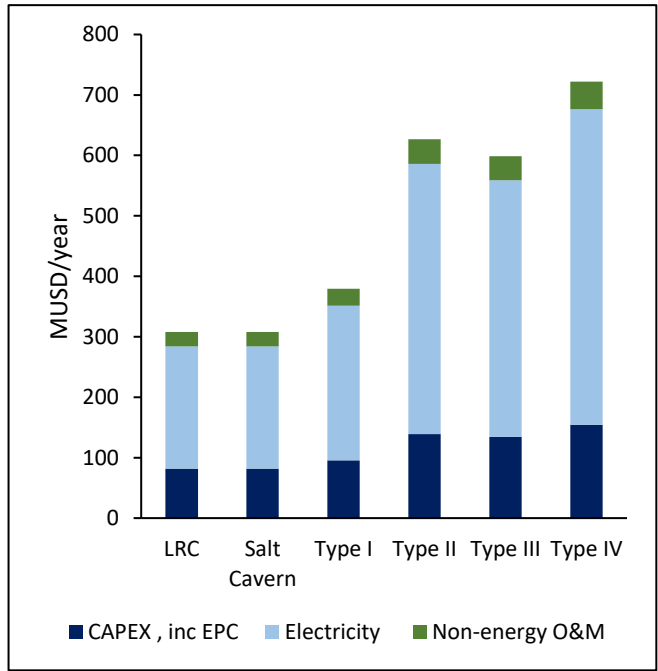


Figure 20: Cost breakdown of hydrogen compression Case C

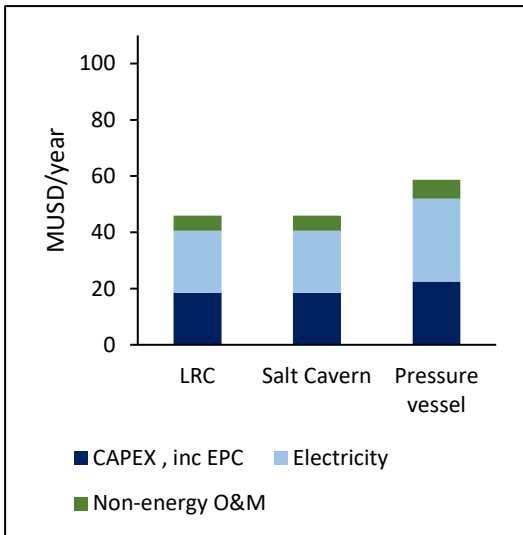


Figure 22: Cost breakdown of methane compression, Case A

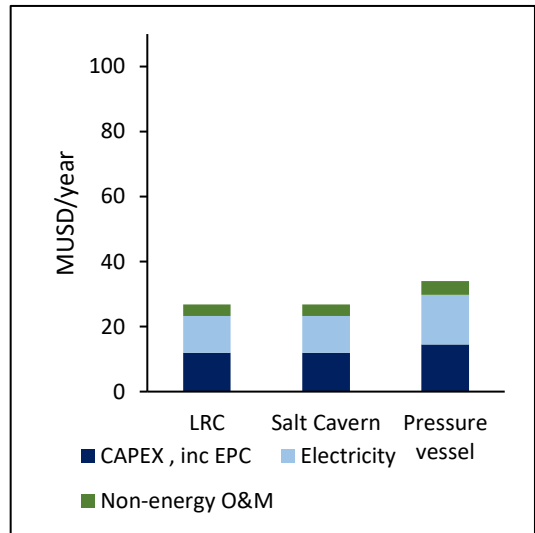


Figure 21: Cost breakdown of methane compression, Case B

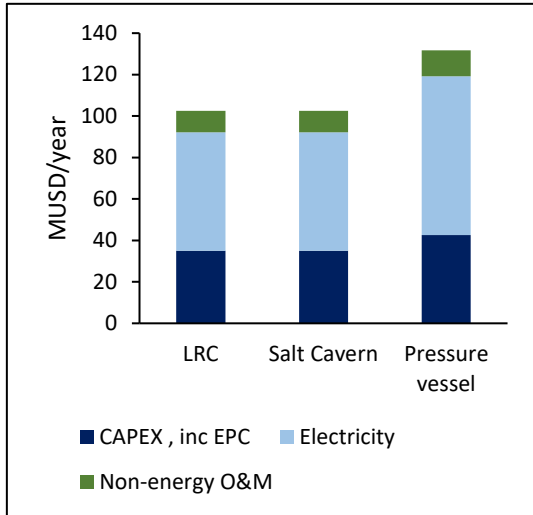


Figure 24: Cost breakdown of methane compression, Case C

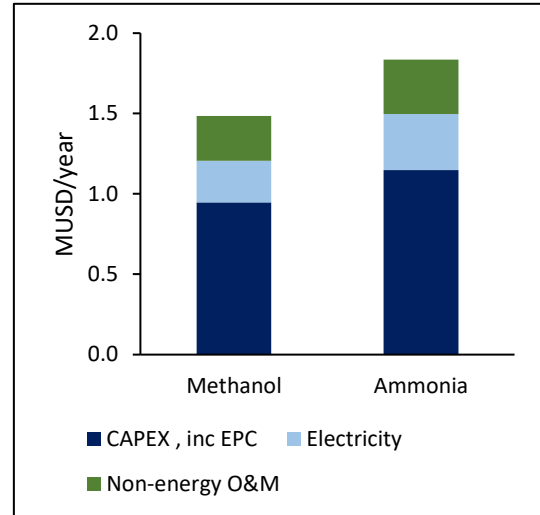


Figure 23: Cost breakdown for methanol and ammonia compression, Case A

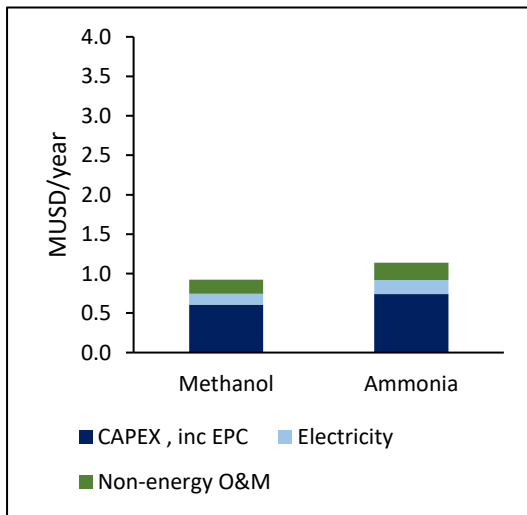


Figure 26: Cost breakdown for methanol and ammonia compression, Case B

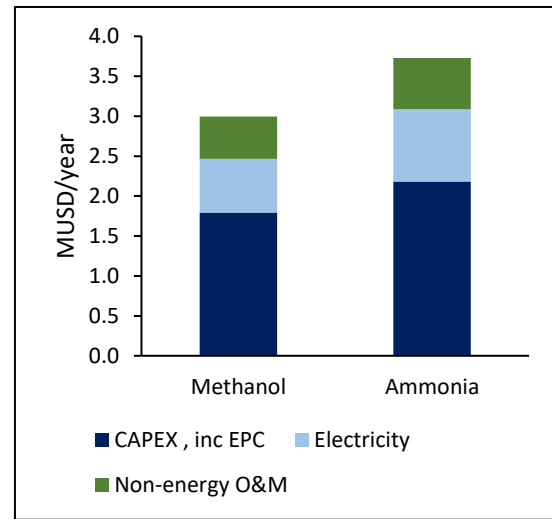


Figure 25: Cost breakdown for methanol and ammonia compression, Case C

As can be seen by Figure 23-Figure 25, the cost breakdown of methanol and ammonia compression deviates from this trend as the CAPEX cost has the largest share in all the cases. This is primarily due to the low electricity requirement for compression of these fuels and thus more of the costs are associated with the initial building of infrastructure.

Figure 27-Figure 29 present the cost breakdown of the total annualized cost of hydrogen storage technologies for each case.

In Figure 27, pressure vessel storage is much more capital intensive as compared to geological storage since single vessels can only carry up to 100-200 kg of compressed hydrogen (as of now), implying that more than 100,000 vessels would be required to meet the storage requirement. The annual CAPEX cost for a salt cavern is 12 M\$/year however it is 4257M\$/year for an LRC signifying the capital-intensive nature of building the latter. Figure 28 shows a similar trend with LRC being the clear outlier.

In Figure 29, the CAPEX cost of the pressure vessel storage technologies is much lower than the geological storage options, particularly LRC, because building a small-scale geological storage is capital intensive. The LRC is the most expensive option in this case.

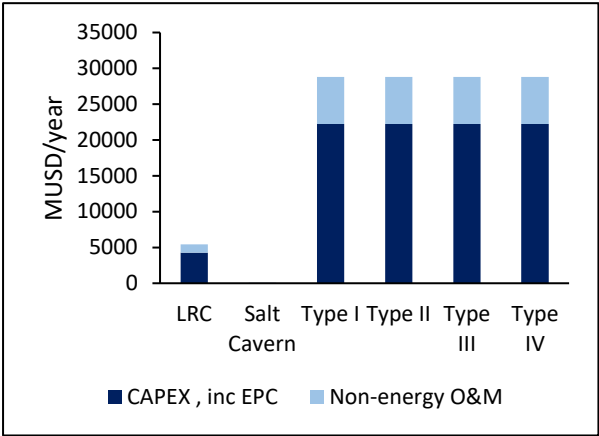


Figure 27: Annual cost of hydrogen storage, Case A

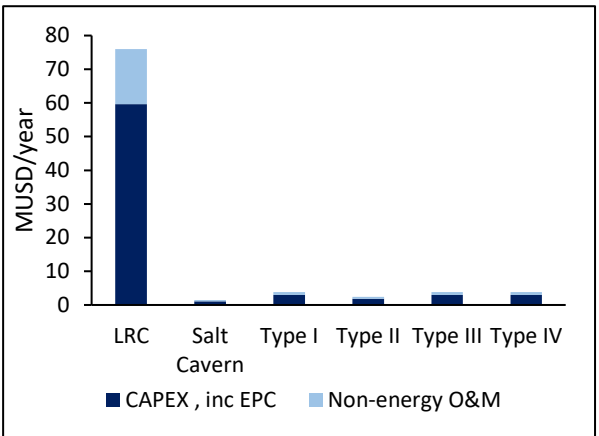


Figure 28: Annual cost of hydrogen storage, Case B

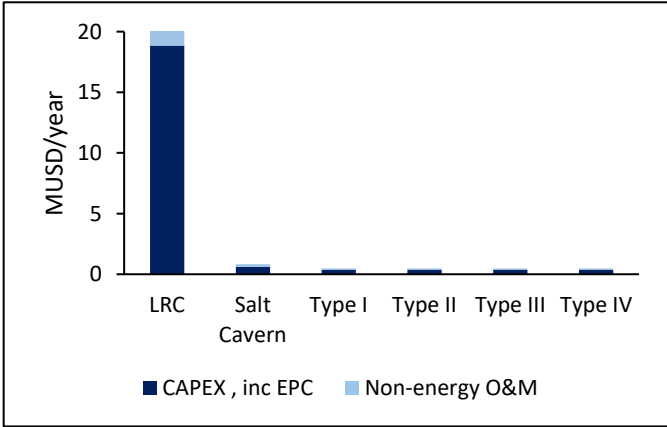


Figure 29: Annual cost of hydrogen storage, Case C

As illustrated by, Figure 30-Figure 32, the cost breakdown for methane storage is dissimilar to hydrogen storage. The LRC is the most capital-intensive option in every case and the pressure vessel storage is almost as cheap as the salt cavern storage for Case B and C. Overall, the annual capital cost for storing methane is far lower than the cost for storing hydrogen due to the larger volumes needed for hydrogen storage.

Referring to Figure 33-Figure 34, the annual cost of storing methanol for seasonal storage is the lowest amongst all the fuels. This can be seen from the large difference in the scale of the graphs. For Cases B and C, it is apparent that ammonia is less capital intensive as compared to methanol which is slightly unexpected. This could be because the cost of methanol storage within the industry is currently more expensive as compared to ammonia since the financial information utilized for these calculations were obtained from literature and industrial data.

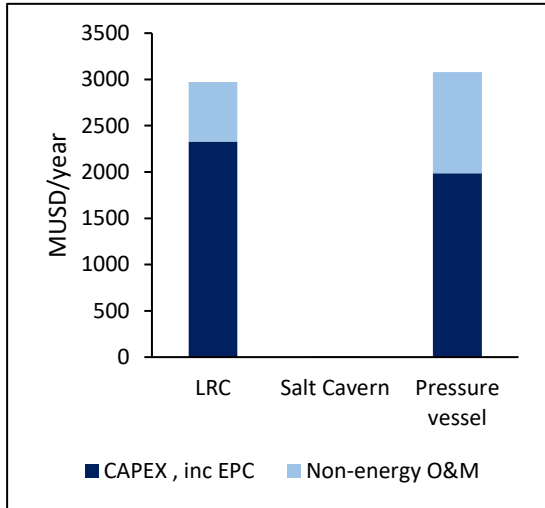


Figure 30: Annual cost of methane storage, Case A

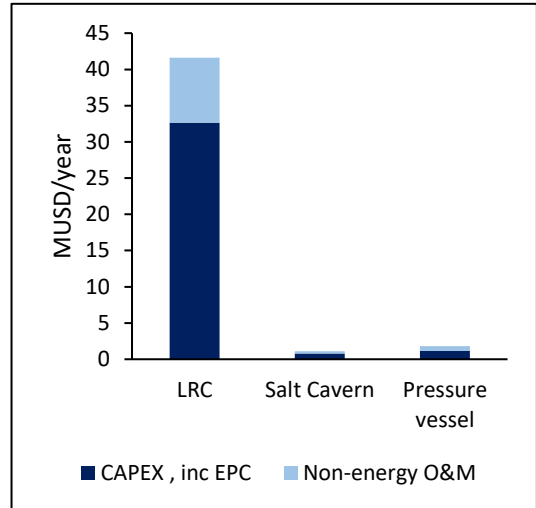


Figure 31: Annual cost of methane storage, Case B

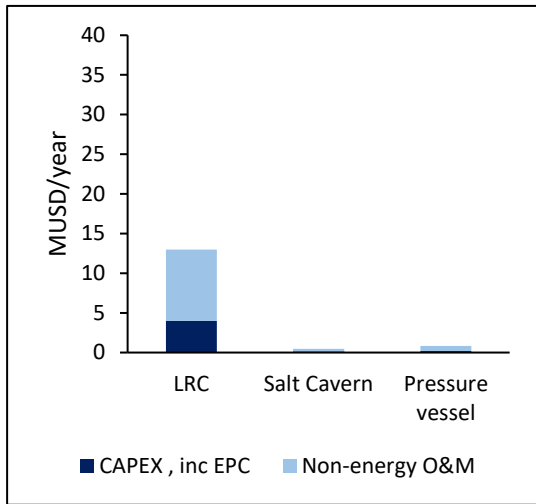


Figure 32: Annual cost of methane storage, Case C

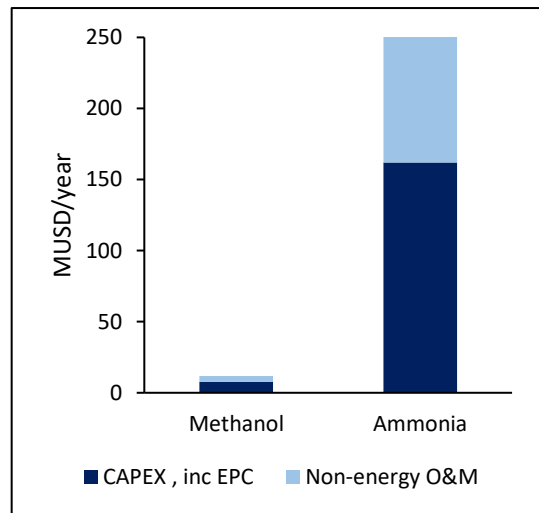


Figure 33: Annual cost of methanol and ammonia storage, Case A

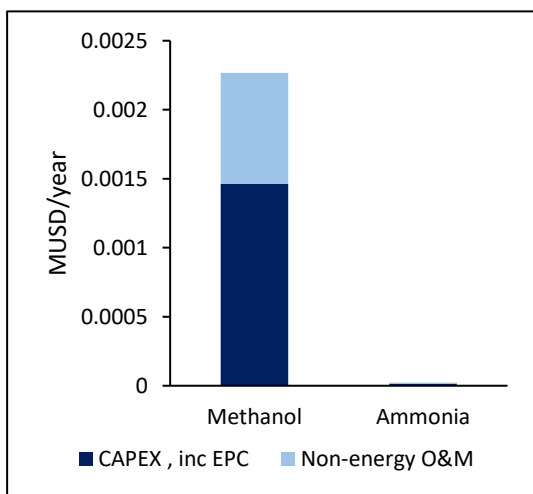


Figure 35: Annual cost of methanol and ammonia storage Case B

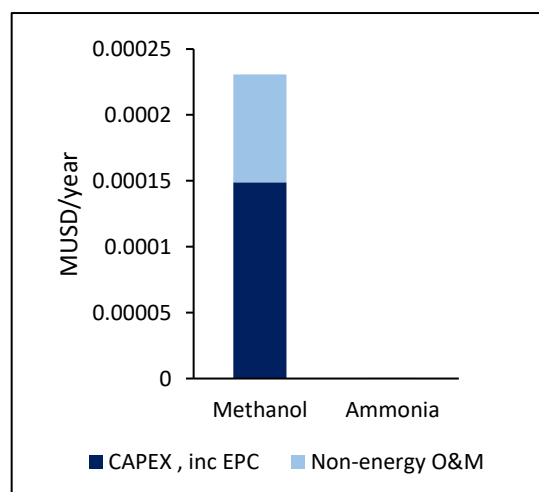


Figure 34: Annual cost of methanol and ammonia storage, Case C

8.3.2. Levelized cost breakdown

It is interesting to analyse the breakdown of the total costs to understand the share of cost attributed to each process included within the entire model. For utilizing hydrogen as seasonal storage, visualized by Figure 37, the cost of the storage accounts for the majority of the total levelized cost and followed by the production of the fuel (input price) due to the large amount of fuel that is required for storage. Salt cavern storage has the lowest cost, 0.3 €/MWh and the cost of fuel represents 46% of the total levelized cost. Pressure vessel storage has the highest storage cost, 500 €/MWh (Type IV) and the fuel input cost is only 14% of the total levelized cost. In seasonal storage application, the cost associated to loading and lost fuel is negligible. In Figure 36 and Figure 38 the cost of loading has a larger proportion of the total cost since the compression costs are higher in these cases. This is due to the proportionally higher fuel power demand and higher utilization of the compressors.

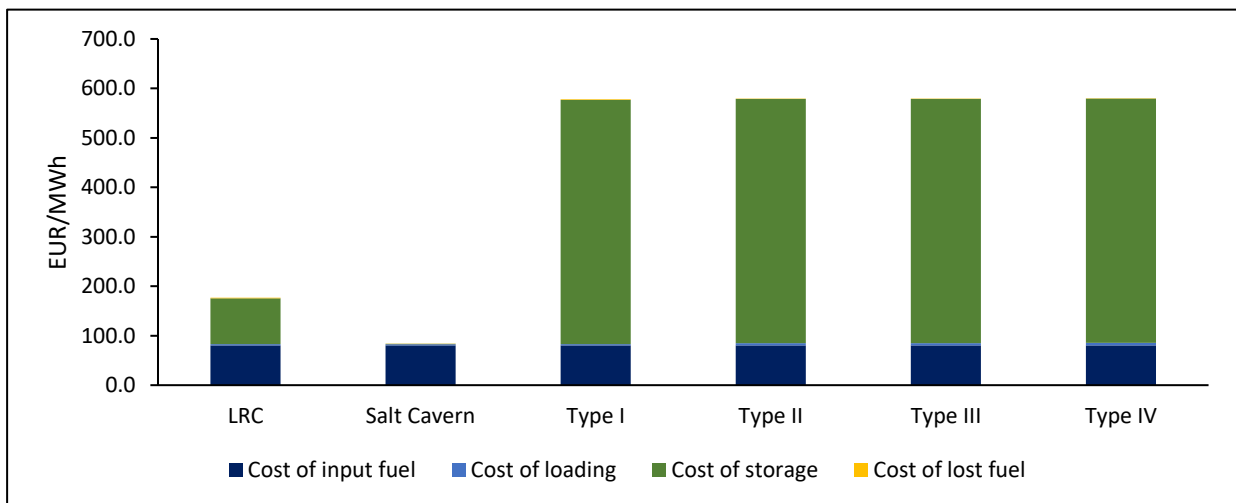


Figure 37: Levelized cost breakdown for hydrogen storage, Case A

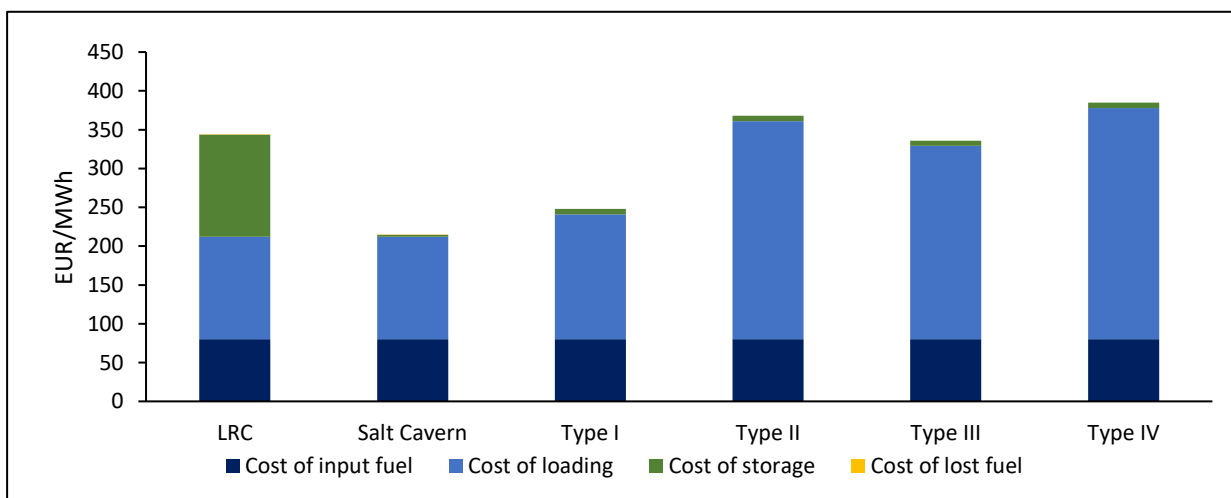


Figure 36: Levelized cost breakdown for hydrogen storage, Case B

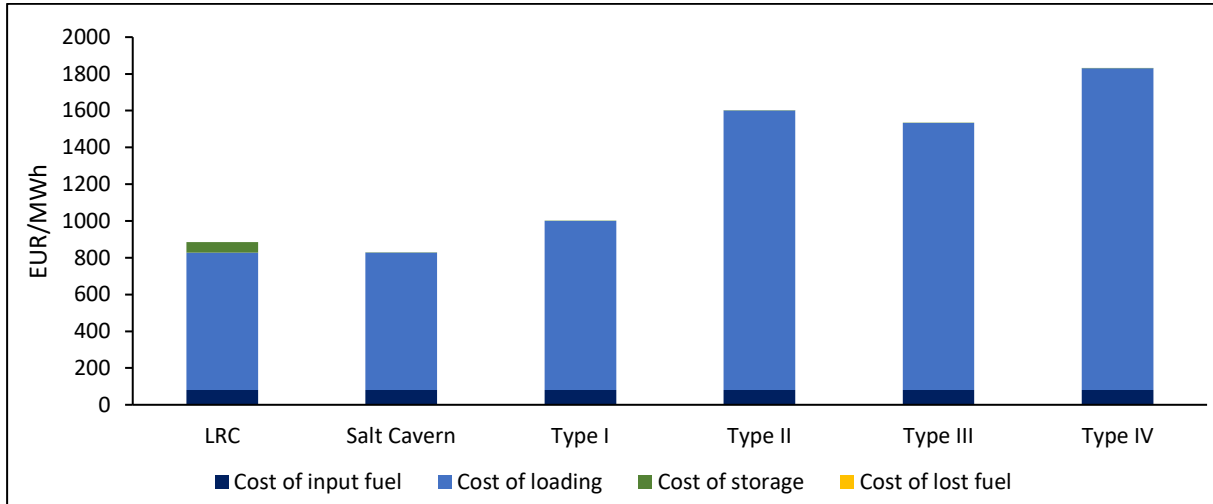


Figure 38: Levelized cost breakdown for hydrogen storage, Case C

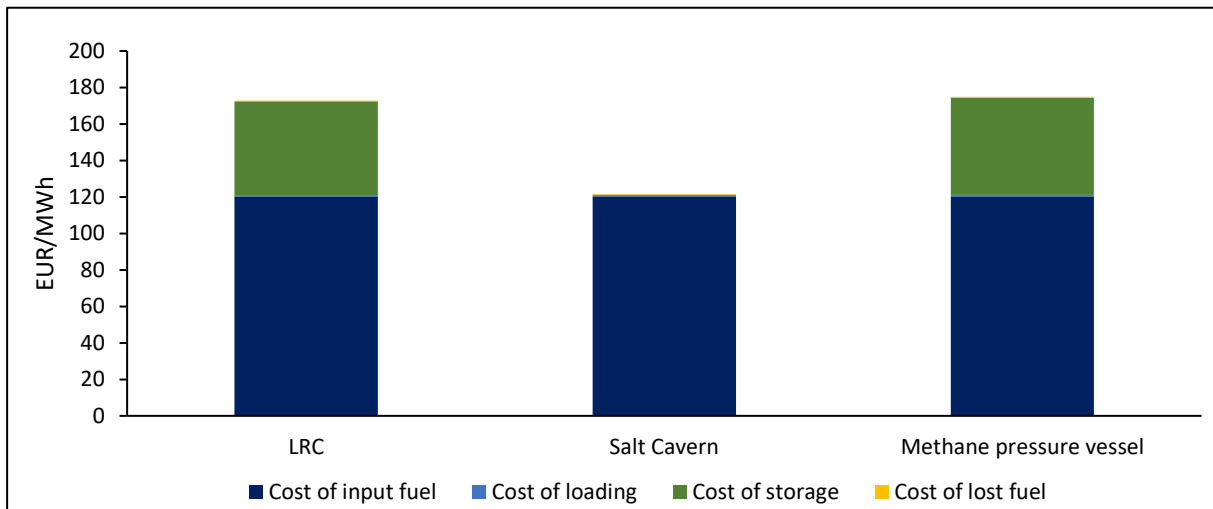


Figure 39: Levelized cost breakdown for methane storage, Case A

Similar to Figure 37 and Figure 36, salt cavern storage continues to be the cheapest of the technologies in Figure 38 with a total storage cost of 3 €/MWh. Additionally, the cost of storage in an LRC continues to be expensive for all the cases as compared to the other storage types.

Storing methane for seasonal storage follows a similar trend however the cost of input fuel accounts for a larger share of the total levelized cost as compared to the storage and loading costs individually (Figure 39). Taking the example of the pressure vessel, the cost of input fuel is 120 €/MWh and the cost of storage and loading is 53 €/MWh and 1 €/MWh respectively. This implies that the reducing the cost of producing synthetic methane through methanation powered by renewable energy is imperative to reducing the overall cost of storage.

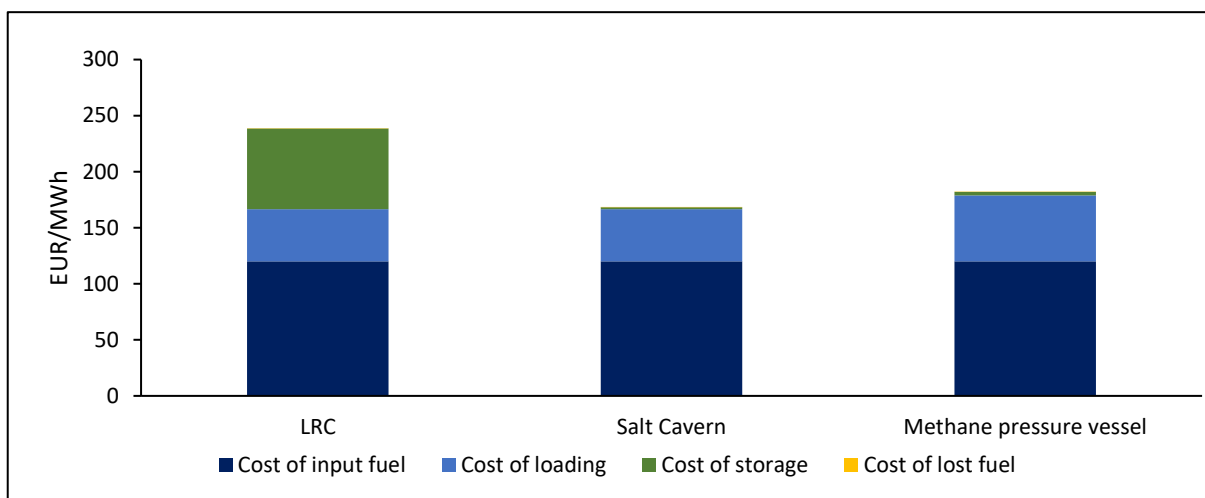


Figure 40: Levelized cost breakdown for methane storage, Case B

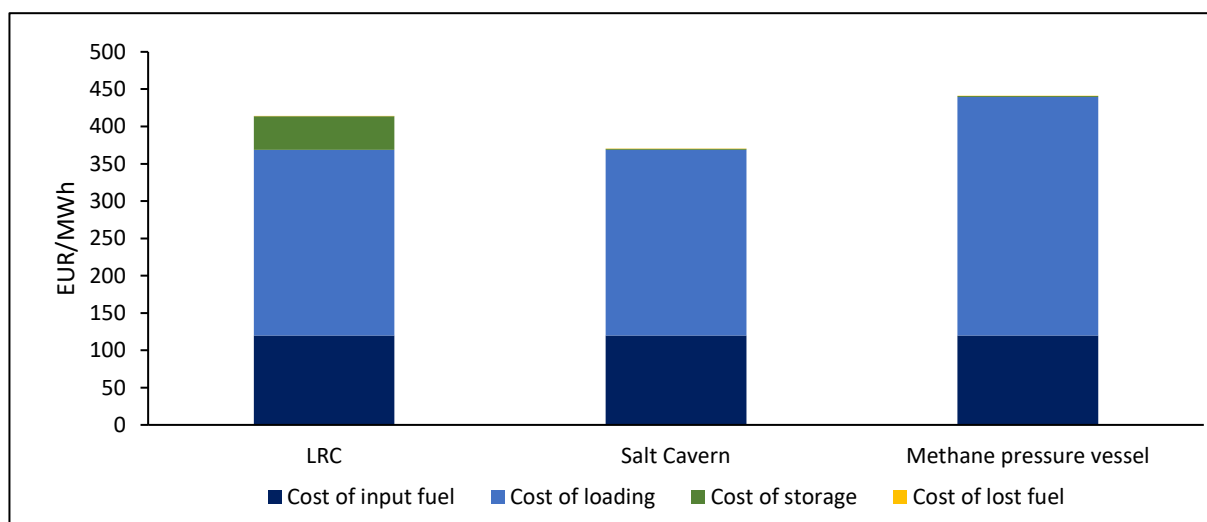


Figure 41: Levelized cost breakdown for methane storage, Case C

This is also seen from Figure 40 and Figure 41 where the input fuel price is a dominant factor although the cost of loading increases.

The breakdown of levelized costs for methanol and ammonia also emphasizes that the high input fuel price has a large effect on the storage of these fuels since it also magnifies the cost of lost fuel due to leakages. Moreover, for weekly and daily storage the cost of storage of methanol and ammonia is almost negligible as compared to the cost of loading and the cost of the fuel as shown by Figures Figure 42-Figure 44.

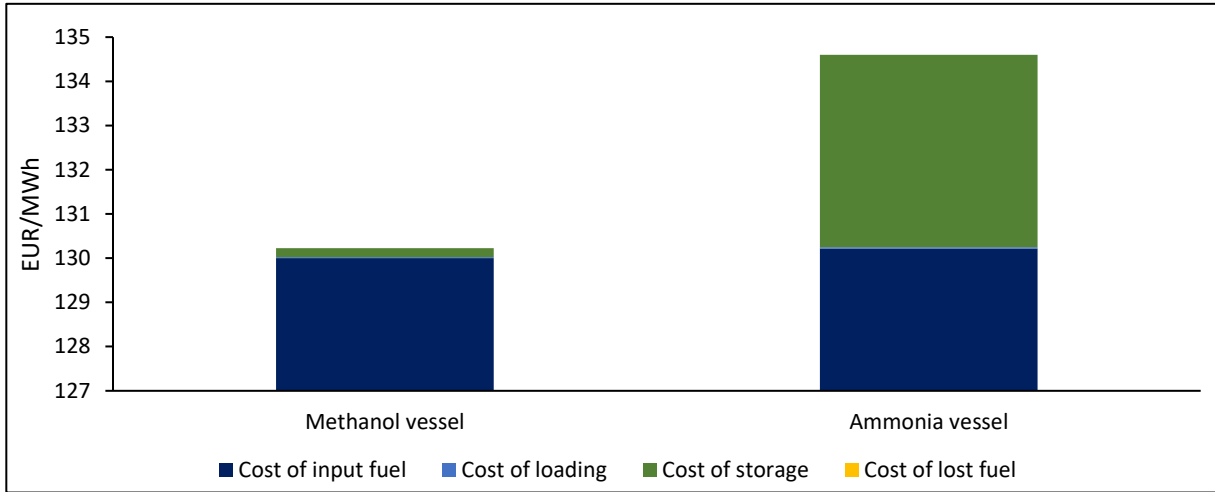


Figure 42: Levelized cost breakdown of methanol and ammonia, Case A

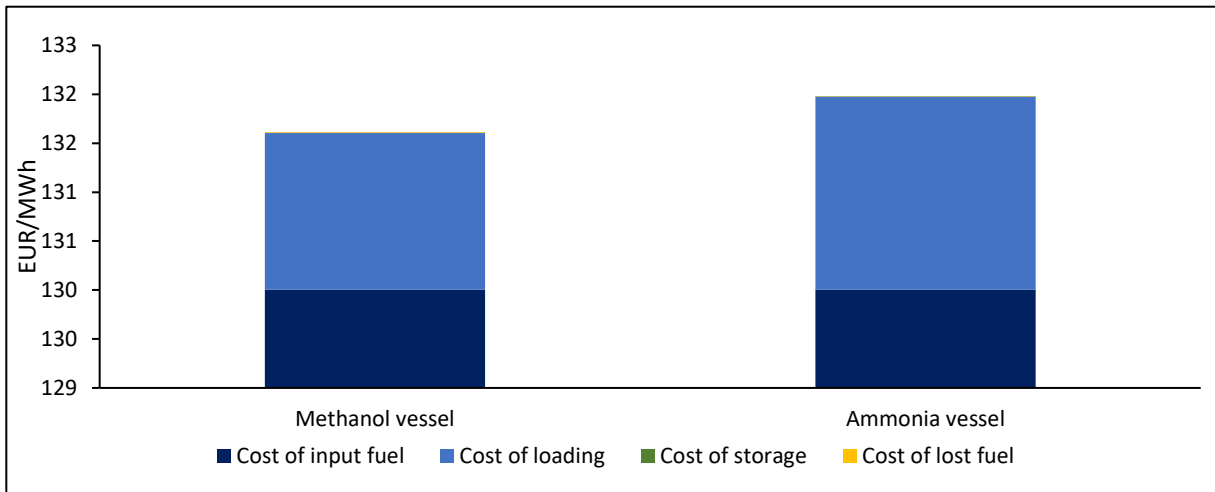


Figure 43: Levelized cost breakdown of methanol and ammonia, Case B

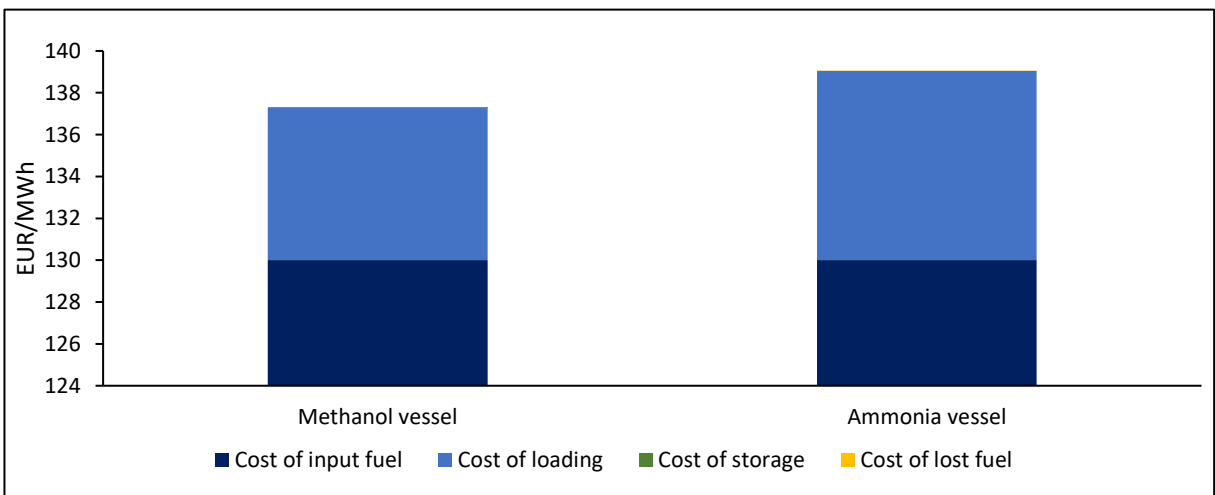


Figure 44: Levelized cost breakdown of methanol and ammonia, Case C

8.3.3. Levelized cost of storage

Seasonal storage requires a large scale, low cost per kWh solution with a low self-discharge rate. It has been concluded that storage technologies utilizing similar fuels are assumed to have similar leakages rates, thus the main factors for assessing the feasibility for seasonal storage are the LCOS, the size of storage required to meet a certain power demand and finally any other technical or operational limitations.

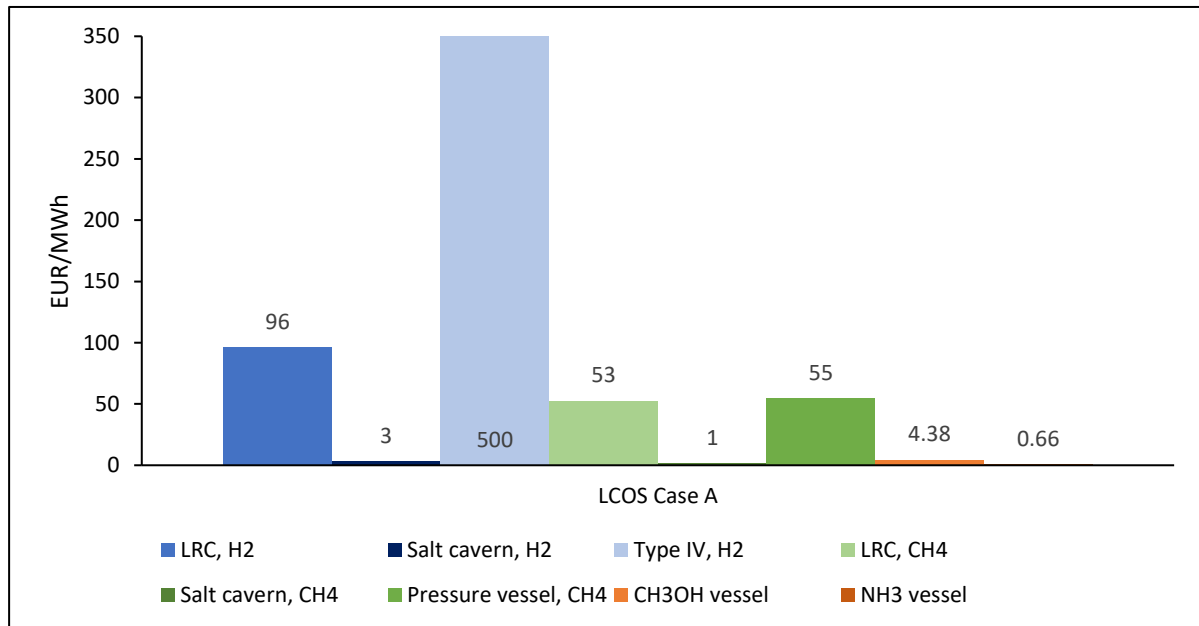


Figure 45: Levelized cost of storage, Case A

Figure 45 presents the LCOS for hydrogen, methane, ammonia and methanol for each type of storage technology for a discharge power demand of 14 GW over one annual cycle. Since the emphasis of this study is more towards assessing UHS, only the LCOS of the type IV vessel is utilised as a comparison.

It is evident that the above ground storage of methanol in pressure vessels has the lowest LCOS, 4.4 €/MWh, largely owing to the combination of high volumetric density, relatively low CAPEX of storage and low compression power required for storage. It was calculated that the methanol storage capacity would have to accommodate 11,235,000 m³ of methanol stored at an operating pressure of 20 bar to meet the discharge power demand. In comparison, hydrogen stored in a salt cavern at 200 bar has an LCOS of 3 €/MWh however requires over ten times larger storage volume, 131,260,000 m³ for meeting the same power demand.

Although methanol has the lowest LCOS the production of methanol is inherently more expensive currently and the energy efficiency of the entire pathway is lower as compared to the production of hydrogen due to additional thermochemical reactions required with CH₄, CO₂, and steam (H₂O) as feedstock (without considering end use).

Between the two UHS technologies analysed, salt cavern storage has a lower LCOS, is a more mature technology, has a simpler construction/execution process, is less environmentally destructive and provides superior gas tightness without reinforcements. The process of salt leaching is also less capital-intensive than implementing a steel lining and concrete reinforcement that encases an entire rock cavern. Additionally, the only LRC facility which is currently in operation on a pilot scale (100m³), is implying that it will take a few years for this technology to be feasible on a large scale for seasonal storage.

Moreover, storing methane in a salt cavern has a lower LCOS of 1.2 €/MWh as compared to hydrogen at 3€/MWh although the price of green methane is much higher than the price of green hydrogen in the model as per the cost breakdown. This is directly related to the fact that storage of methane requires less volume, 39,000,000 m³, 3 times less than the volume required for hydrogen storage as a result of the higher volumetric density of methane. When comparing the LCOS of ammonia and methanol, it is evident that methanol is more economically feasible due to its higher liquid density (792 kg/m³ vs 636 kg/m³), given that the calculation for storage volume was significantly impacted by density differences.

The cost of storing hydrogen in pressure vessels is much higher because the storage capacities are very low [163]. They are also currently mostly utilized for vehicular applications and utilizing them to store hydrogen on a seasonal scale would require large quantities of material available land. The risk of hydrogen leak and material embrittlement is also quite grave, although the hydrogen can be stored at much higher pressures (up to 700 bar).

Furthermore, the compression costs are insignificant compared to the cost of input fuel and the storage cost itself. This is expected since seasonal operation is defined as having a single charging cycle lasting a period of approximately 6 months. It is also evident that the fuel price accounts more a sizeable part of the total system costs per year, and sometimes higher than the cost of storage itself.

Interestingly the LCOS for a seasonal storage was more sensitive towards electricity price than fuel price: Table 20 shows the LCOS with different electricity and fuel prices. The lowest LCOS values occurred at a fuel price of 80 €/MWh H₂ and electricity price of 15 €/MWh_{el}. This signifies that a reduction in electricity prices in the future holds substantial potential in reducing overall costs of hydrogen storage for seasonal operations, due to the compression energy requirement.

In order to compare the LCOS for H₂ to literature, the specific price per weight was calculated for a salt cavern and LRC. The cost of storing hydrogen in a salt cavern is reportedly 1.61 \$/kg whereas in this model the price is calculated to 0.11\$/kg H₂ [27]. The difference in values obtained could be due to a range of inputs, e.g. difference in assumed utilization profile or a different scaling factor utilized within this model, especially the latter has a significant impact on the cost of geological storage. There is less data available on LRCs since only few have been built for piloting but given the high capital costs of setting up the storage it is understandable that the cost of storage would be much higher than that for a hard rock cavern.

Table 20: Impact of electricity price and fuel price on LCOS of hydrogen

Sensitivity Parameters		Seasonal Storage LCOS (€/MWh)		
Fuel price (€/MWh)	Electricity price (€/MWh)	LRC	Salt	Type IV pressure vessel
80	30	95.85	3.00	499.60
75	30	95.83	2.98	499.57
70	30	95.80	2.95	499.55
85	30	95.88	3.03	499.62
90	30	95.90	3.05	499.65
95	30	95.93	3.08	499.67
100	30	95.95	3.10	499.70
80	25	95.63	2.78	499.02
80	20	95.40	2.55	498.43
80	15	95.18	2.33	497.85
80	35	96.08	3.23	500.18
80	40	96.30	3.45	500.76
80	45	96.53	3.68	501.34
80	50	96.75	3.90	501.92

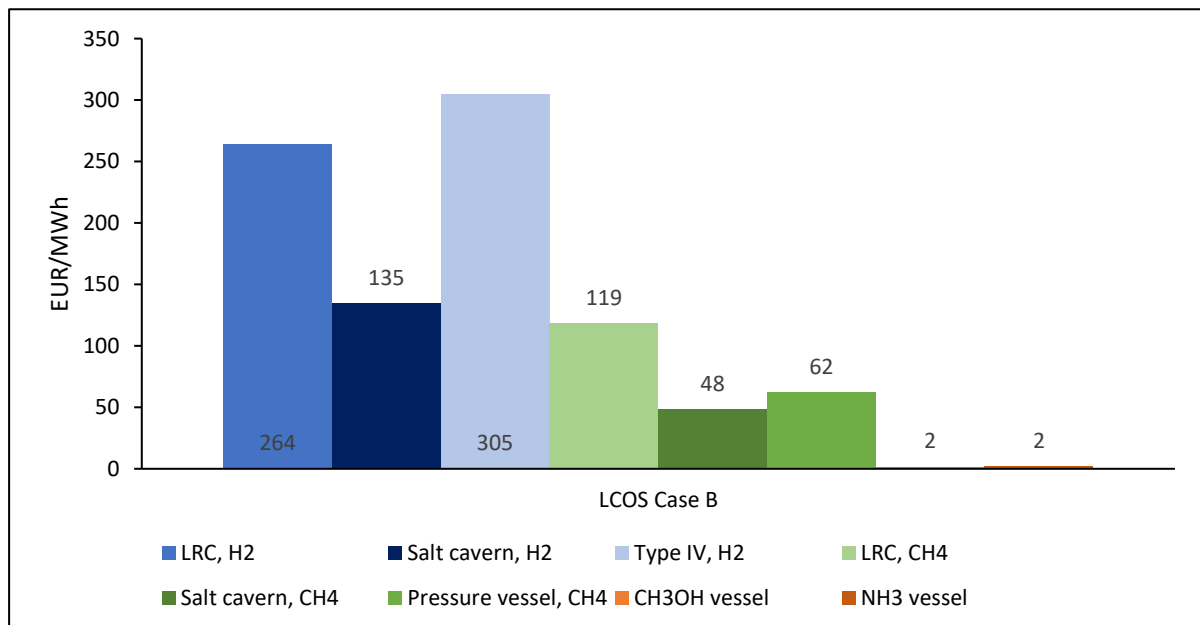
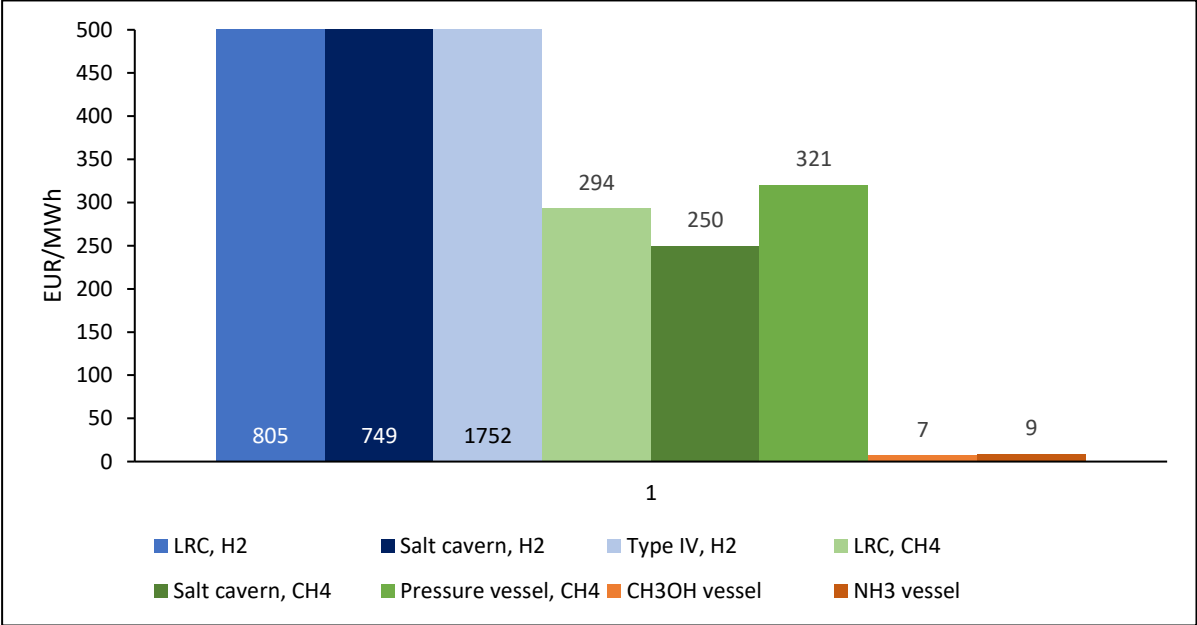


Figure 46: Levelized cost of storage, Case B

From Figure 46 it is evident that it becomes more expensive to store hydrogen in UHS for weekly storage applications. The LCOS of salt cavern storage increases to approximately 135 €/MWh which is still lower than that of pressure vessel storage at 305 €/MWh, the LCOS of LRC storage falls between these two at 264 €/MWh. Thus, the difference between the cost of storage in a pressure vessel and LRC decreases when the size of storage decreases, and annual cycles increase. Methanol and ammonia storage are still cheaper than hydrogen storage, but it is evident that the high cost of storage for all the fuels decreases the economic feasibility of synthetic fuels in the weekly application.

Considering the cost breakdown shown in Figures Figure 37Figure 44 it is also evident that the cost of loading/unloading incurs a more significant part of the cost due to the need for more charging cycles. The results also suggest that in weekly and daily storage applications carbon neutral fuels are cheaper than hydrogen, with methanol being the cheapest form of storage in every case as shown by



47. Table 21 presents the capital cost of each fuel storage for seasonal storage operation on a mass basis.

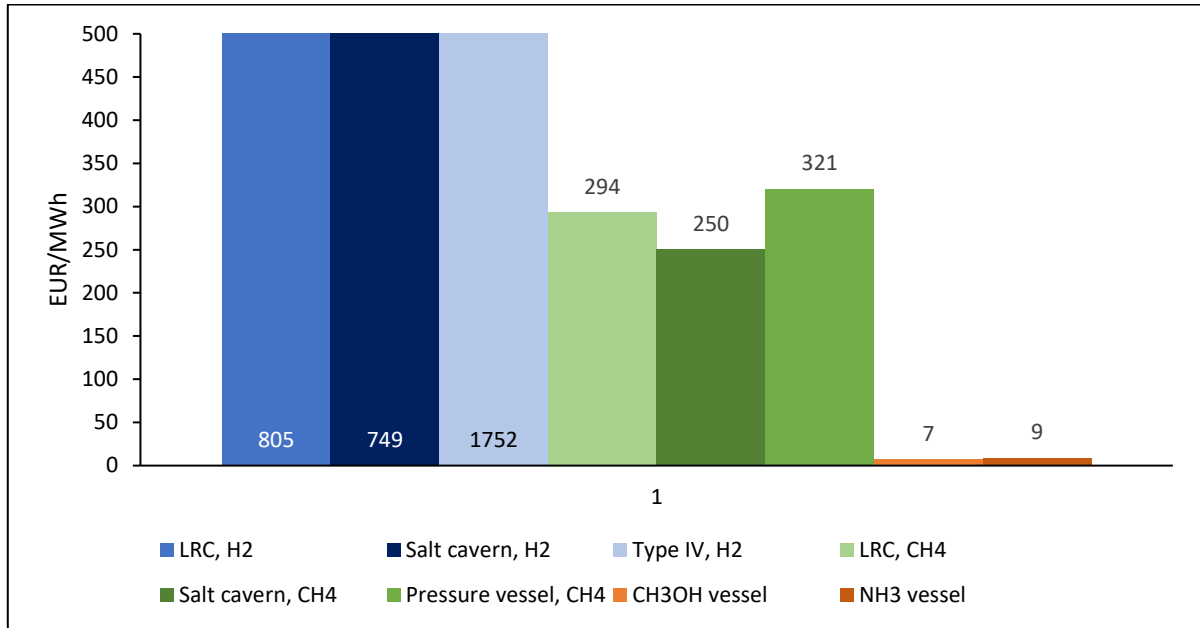


Figure 47: Levelized cost of storage, Case C

Table 21: Cost of fuel storage overview for seasonal storage

Storage	Storage capital cost (\$/kg _{fuel})
Salt cavern, hydrogen	0.1
LRC, hydrogen	39.5
Type II pressure vessel, hydrogen	110.2
Salt cavern, methane	0.03
LRC, methane	9.1
Pressure vessel, methane	23.4
Pressure vessel, methanol	0.01
Pressure vessel, ammonia	0.02

According to the results, the most economical solution for large scale hydrogen storage over time scales of >10 weeks is compression of hydrogen to 200 bar and storage in a salt cavern. Compressed hydrogen storage in an LRC is the second-best option. Both LRC and salt cavern storage show considerable reduction in cost as the storage size increases, although salt caverns appear to be more cost-effective due to lower capital investment cost and larger maximum capacity available (need to be built at a slower rate than LRC to meet growing energy storage capacity). Salt caverns can also ensure gas tightness due to the inertness of salt, thus maintaining hydrogen purity which is vital in most end-use cases.

LRC and salt cavern storage are usually available in different locations. While the latter is geographically limited in that salt beds are mainly situated in USA, Europe and UK, the former can be built in any region with low-porosity rock with sufficient structural strength such that it absorbs the load of the gas. Thus, the best choice for seasonal storage depends on the location of the project, with LRC being invariably be more costly option due to its more complicated structure; it costs 39.5 \$/kg as compared to 0.1 \$/kg for a salt cavern. Furthermore, although large-scale geological storage has a high initial installation cost for seasonal storage, the operating costs are significantly lower over the lifetime of the storage implying that the return on the initial investment is possible over a shorter period of time.

The capital cost of storing hydrogen within pressure vessels (\$110/kg) seems to be too high and not viable for large quantities of hydrogen, however, it becomes more cost-effective for storing smaller quantities of hydrogen. Hydrogen pressure vessels are also the most prevalent form of hydrogen storage. As eluded to earlier, the main drawback of the technology is the material and land requirement for these vessels. Table 22 presents the favoured hydrogen storage technologies for different timescales and hydrogen production capacity based on the results.

Table 22: Hydrogen storage choice depending on application

Timescale of storage	Mass of storage	Hydrogen storage technology
< 1-2 days	< 30 t	Pressure vessel storage
< 10 days	< 300 t	Salt cavern storage, type II pressure vessel storage
> 5 months	> 1 Mt	Salt cavern storage and LRC storage

Synthetic methane is a viable alternative to hydrogen and has already been successfully stored within salt caverns and depleted oil & gas fields. Storing methane in salt cavern or LRC is also cheaper under the assumption that the storage costs are same. It would also be easier to utilize methane for seasonal storage as it would require less modifications to the present gas infrastructure and transport chain. The drawback of methane is that it contains carbon, which results in carbon dioxide emissions upon combustion, and necessitates commercial scale CCS technology for the synthesis and making the fuel carbon neutral.

Ammonia storage is cheaper than methane and requires less energy for compression, however it has competing uses which might hamper its use as a form of energy storage primarily for the energy sector. On the other hand, its mature production technology and the robust channels of transportation could improve economies of scale, if efficient sector coupling is achieved. Methanol storage is even cheaper than ammonia since it is a liquid at ambient conditions. Similar to methane, the carbon in the fuel means that CCS is needed, for which technology is not mature and remains expensive.

It is also more likely that methanol is used more widely within the energy sector due to the highly competitive demand for ammonia by the fertilizer industry.

Hydrogen is the base of all the fuels discussed within this study. In order to accelerate investment within the production of hydrogen it is vital for governments to promote a clear strategy involving ambitious targets for electrolysis capacity expansion. Further research and development is required to improve electrolyser efficiency and to achieve economies of scale. There is also a critical need to provide financial support to research initiatives focused on developing novel methods of producing ammonia and projects investigating the efficient conversion of hydrogen to methane and methanol. Lastly, increasing public awareness and knowledge surrounding hydrogen and its benefits is imperative to proving that its integration within the energy sector and other hard-to-abate sectors has more benefits than risks involved.

9. Contribution to sustainability

The transition of utilizing traditional fossil fuels to produce energy to clean renewable sources is vital in mitigating the catastrophic consequences of climate change. Although the sector has made significant progress in integrating a higher share of renewable generation on the grid, achieving a 100% RES requires implementing different forms of energy storage and balancing power to ensure flexibility on the grid. It is also crucial that these developments are conducted in a sustainable manner to prevent the lack of resource availability for future generations and to improve inter-generational equity.

This study contributes to achieving a more sustainable future by creating a model that computes the economic cost of utilizing green hydrogen, methane, ammonia and methanol as energy storage mediums for excess renewable electricity. It also aims to compare the technical potential of different green hydrogen storage technologies to help understand which storage option holds the most potential and thus encourage industrial efforts towards investing in these types of storage forms. It is also important to note that the conclusion of this research pointed towards large scale storages that require fewer precious metals and material throughput as compared to ramping up production of environmentally harmful storage such as lithium ion batteries.

Referring to the UN Sustainable Development Goals, advancing research on hydrogen storage and carbon fuels as energy vectors supports the target of achieving ‘affordable, clean and reliable’ sources of energy (SDG 7). Improving the knowledge surrounding hydrogen within the industry also helps its adoption in hard to abate sectors such as transportation and industry.

As well as this, this research aims to elucidate the concept of utilizing synthetic fuels, not commonly utilized within the energy sector for energy storage purposes. Since methane, ammonia and methanol are an integral part of numerous industrial and chemical processes, this research encourages cross-sector utilization of synthetic fuels which leads to more efficient utilization of resources from a holistic supply chain perspective.

Public acceptance and trust play a key role in the success of hydrogen as an energy storage mechanism or an end use fuel. It is well known that hydrogen is a critical part of the energy transition however the lack of understanding within the general public and uncertainty surrounding its feasibility is a social barrier to investment and innovation. This also affects governmental policy and the building of frameworks that inspire companies to enter the hydrogen market. Increasing the knowledge regarding hydrogen will encourage. This will lead to more companies entering the market and an increase in competition which will inevitably decrease the price of producing and storing hydrogen. Thus, making it more accessible as a fuel source for a wider population as well as helping large manufacturers to move away from traditional fossil fuel generation as hydrogen becomes more cost competitive.

10. Conclusion

Implementing storage technologies that offer flexibility on the short term as well as the long term is imperative to fully decarbonizing the power sector. Seasonal storage of hydrogen has the potential to facilitate higher integration of renewable energy by providing adequate capacity on the grid to absorb shocks to grid caused by fluctuating weather patterns and ensure uninterrupted power supply. Deployment of hydrogen for fuel cells for transportation or for utilization in the industry also requires economically feasible hydrogen storage solutions. Nevertheless, storing hydrogen is challenging and thus it is important to consider alternative fuels as energy vectors.

The most important pre-requisites for a fuel storage to be a feasible form of seasonal energy storage are that it i) is easy to scale; ii) exists on a large scale with low costs per MWh; and iii) has a low leakage rate. In order for a specific type of storage to be feasible for hydrogen, it must i) be able to retain hydrogen for long periods of time without reducing its purity; ii) have a fairly low levelized cost of storage; and iii) have no adverse effects on the environment.

Utilizing these parameters, salt cavern storage and lined rock cavern storage were found to be the most feasible forms of large-scale hydrogen storage. Storing hydrogen successfully within the other geological options considered, depleted oil & gas fields and aquifers, has not been achieved due to the presence of bacteria reducing the purity of hydrogen in the long term, the risk of hydrogen leaking into the ground and contaminating ground water, and the high cost associated with geological testing and exploration, among other factors.

The results of the economic analysis indicate that salt caverns are the most cost-effective method of storing hydrogen on a large scale but pressure vessel storage at lower pressure ranges is more feasible for short term storage or smaller scale applications. Furthermore, methanol is the cheapest fuel to store and both methane and ammonia are less expensive to store as compared to hydrogen. All the storage technologies discussed have advantages and disadvantages and the choice of technology is highly dependent on the application/end use. There is no 'silver bullet' fuel or storage and thus it is vital to also consider the synergies between a combination of different technologies providing both long term and short flexibility for further research.

11. Further Work

- The model designed could be further improved by implementing a carbon price cost input within the total cost of storing carbon neutral fuels, this would better emulate the actual additional costs of producing the fuels from e.g. CCS.
- Carbon neutral fuel storage is not likely to be the lone storage technology utilized for providing flexibility to the grid or a project level application. It is more likely that it will be utilized in combination with BES. Thus, further work should assess the optimized usage of both a BES and carbon neutral fuels as energy storage.
- The transportation cost is also not included which is a major source of expenditure within the hydrogen supply chain e.g. feeding hydrogen into the regional gas infrastructure, long distance shipping costs, or transport by road by trucks.
- Another improvement to the method would be to calculate the storage cost based on varying electricity prices based on VRES production, this way the model could be utilized for forecasting cost of storage given the time of day and the demand side load. This would also be beneficial if the model were to be applied to a specific case, based on a real-life project e.g. conducting an analysis of storing electricity for a wind farm which is connected to the grid versus an isolated energy grid. Further to this, analysing the potential of geological storage depending on the location would also be preferable e.g. analysing the potential of salt cavern storage in Germany.
- It would be beneficial to add the end use component i.e. efficiency and cost of burning methanol in engines or utilizing hydrogen in fuel cells. This also includes the cracking of ammonia and methanol if converted back to hydrogen for use and the efficiencies related to the multiple conversion steps.

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