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Hydrogen as a storage medium in Scotland

Szebasztian Csernik-Tihn and Jamie Mitchell, Gemserv

Katriona Edlmann, The University of Edinburgh

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1 Executive summary

1.1 Aims

Scotland has an ambitious net zero target of 2045, five years earlier than the rest of the UK. As the share of renewables increases in power generation, periods when there is too little energy or more than can be accommodated, known as intermittency and curtailment respectively, are becoming a challenge to fully realising Scotland's renewable potential.

This report investigates the options for storing energy in the form of hydrogen in Scotland and its potential for reducing curtailment. We also investigate the role of hydrogen peaking power for electricity generation during times of low renewable energy generation.

1.2 Findings

- Hydrogen storage will play an important role in balancing an energy system that has large amounts of intermittent renewable energy. It can supplement other forms of energy storage, such as pumped hydro and batteries, due to the greater scale and duration of storage provided by hydrogen.
- All hydrogen storage technologies are anticipated to support the flexibility of the energy system. The size of the role and use cases will vary significantly between technologies, with most of them supporting long-term, weekly, monthly and seasonal storage.
- Different storage solutions have different suitability for deployment in Scotland. Much of this is driven by geology, use case and timescales (Figure 1).

- **Pressurised tanks and vessel storage** are mature, ready for deployment and do not require specific geology. However, tank storage is expensive due to high compression costs and the need for containers that can withstand high pressures.
- **Linepack** (gas stored in the pipe network) will provide a low-cost option for hydrogen storage. However, this is most likely to be used for one-day storage and will have limited usefulness for longer duration storage to cover periods of low renewable generation.
- **Salt caverns** are a mature technology and can store large volumes of hydrogen at relatively low cost. However, salt caverns have not previously been used as flexibly as may be required for hydrogen storage in a future energy system. Additionally, Scotland does not have onshore salt deposits and would need to rely on neighbouring countries to exploit this technology.
- **Depleted gas fields** could be important to unlock high storage capacities rapidly and cost-effectively. Due to the variability in geochemical and microbial factors, each site has to be reviewed on a case-by-case basis, which can be a lengthy process. Although there is a general academic view that they are likely to go through only a few cycles a year to meet seasonal storage demands, our stakeholders' modelling and experience with large-scale natural gas storage has indicated that they could be used more flexibly, potentially supporting monthly or weekly storage.
- **Other porous media**, such as aquifers, have potential in Scotland due to the extensive sedimentary deposits in the Midland Valley. As these are geologically less well-understood, they are also at a lower technology readiness than any other form of geological storage.
- **Lined rock caverns** have high potential in Scotland in the short term. As they do not have geological constraints and can be easily scaled, they could provide a cost-effective and safe technology to dispersed sites and island communities whilst an extensive hydrogen pipeline infrastructure comes online.
- **Liquid hydrogen and hydrogen carriers** could play a role in unlocking Scotland's hydrogen export potential. However, they are less efficient than other storage options and are therefore likely to have a limited role in cutting curtailment costs and providing flexibility to the energy system before an international hydrogen market develops.
- **Metal hydrides**, a form of solid-state hydrogen storage, can store hydrogen at a higher energy density than pressurised or liquid hydrogen, and can be stored at ambient temperatures and pressures. However, these are at a lower technology readiness than compressed gaseous storage, with the conversion being energy intensive.

In addition to the hydrogen storage options listed above, wider considerations include:

- **Electricity storage technologies**, such as batteries and pumped hydro, will be critical for short-term and medium-term storage, as increasing renewable generation will require these technologies to provide stable, reliable and balanced power grid.
- **Hydrogen power stations** can provide more flexibility and greater duration than other sources of electricity supply, assuming hydrogen storage capacity is

developed. Continued electricity supply during long periods of low renewables generation could be achieved with large-scale storage of hydrogen.

- **Hydrogen-fired turbines** are likely to be important for power peaking and low load factor generation. For low load factor generation sites, hydrogen peaking plants are likely to have a lower cost than gas power plants with carbon capture, utilisation and storage.

Hydrogen storage will play an important role in providing flexibility in an energy system that has high penetration of intermittent renewable energy. Due to flexibility, greater scale and duration compared to energy storage alternatives, hydrogen has the potential to reduce renewable curtailment costs, accelerate the decarbo-nisation of the power grid, support Scotland's future hydrogen export market and strengthen energy security.

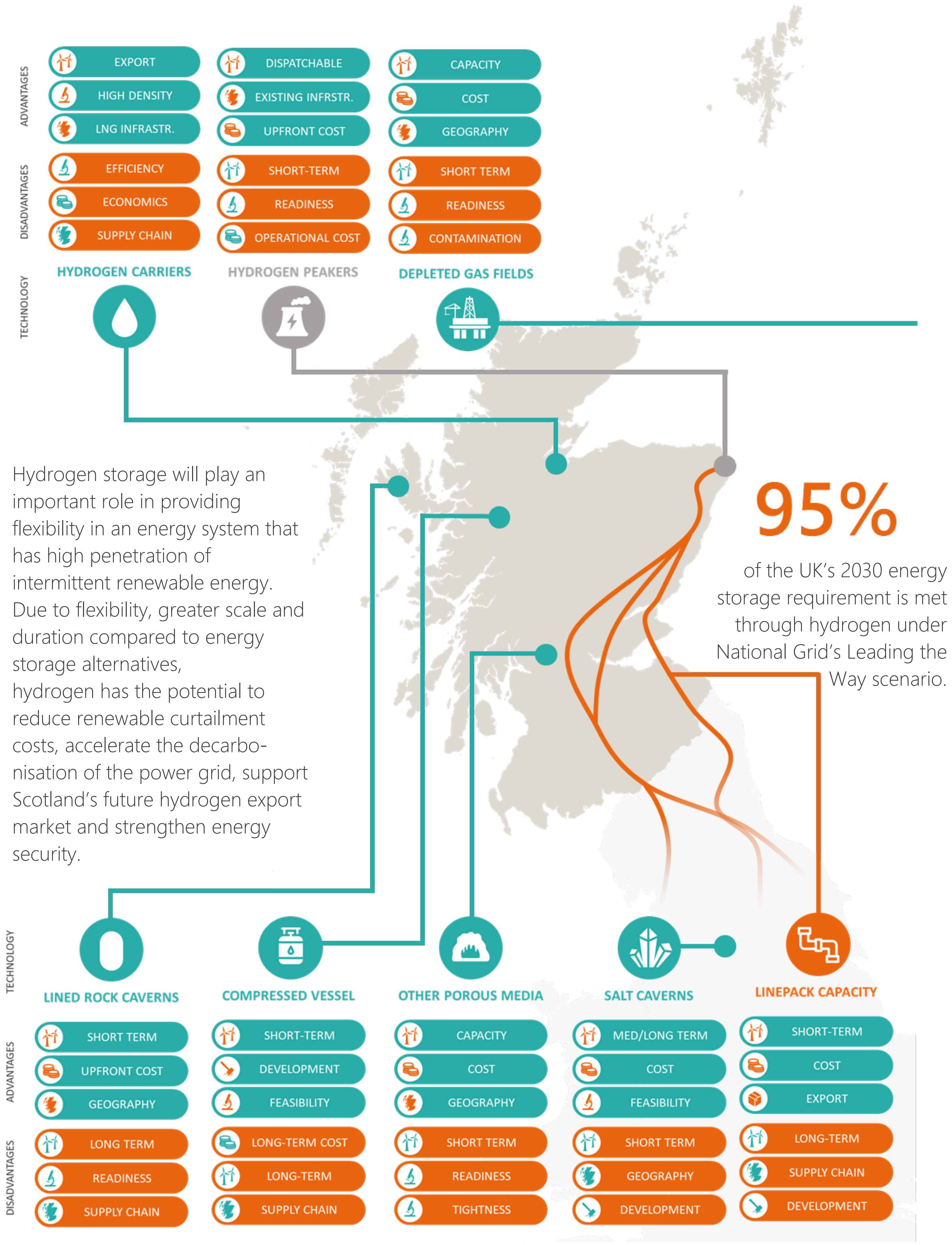

Figure 1 Summary of advantages and disadvantages of hydrogen as a storage medium

1.3 Recommendations for further work

1. **Feasibility studies and real subsurface trials** are needed in the short-term in porous media and lined rock cavern storage due to high suitability in Scotland, limited deployment data and long lead times. With no access to underground salt layers, we recommend identifying potential depleted gas fields that could support a centralised hydrogen storage system in the long term. We also recommend exploring lined rock caverns' potential in decarbonising dispersed sites and island communities in the short term.
2. Clear guidance and information on the production, storage and use of hydrogen could be provided to stakeholders, residents living near hydrogen sites and the general public, as **public buy-in** is key in meeting Scotland's net zero ambitions. This is not only critical to improve the perception of low-carbon technologies and net zero in general, but also to minimise residential opposition and accelerate developments. Therefore, we recommend the Scottish Government work closely with local councils and communities to:
    - make the public aware of the carbon footprint of hydrogen produced under government subsidies, the environmental impact of construction and operation of hydrogen storage facilities and how these facilities aid net zero
    - reassure the public that stringent safety requirements and systems are in place that manage the risk of hydrogen leakage and accidents on site.
3. Policymaking must ensure that regulation and other support mechanisms do not negatively distort the energy storage market framework. UK Government business models could be designed to incentivise investment and developed in tandem with those of other technologies to ensure timely, efficient and a cost-effective energy transition. **Strategic planning**, cooperation between the UK and devolved governments and the emerging Future System Operator will be critical to cut renewables curtailment and maximise the system benefit of energy storage.
4. Welcoming the recent consultation on Offshore Hydrogen Regulation, we recommend that the Department for Energy Security and Net Zero, the Scottish Government, and Ofgem **review the existing onshore hydrogen regulatory framework** and identify regulatory barriers and opportunities for hydrogen storage projects.
5. As hydrogen regulation is fragmented and planning is devolved, the Scottish Government could provide developers and other stakeholders with **clear guidance** on planning, consenting and other regulatory requirements.
6. To support the early development of hydrogen storage projects, the UK Government should review its decision on **pre-2025 interim measures** for hydrogen storage projects. Short-term interim measures could include funding for feasibility studies so that developers are ready to take investment decisions by 2025 when the design of the Hydrogen Storage Business Model is complete.
7. Scottish Government's **continued engagement with key stakeholders**, including hydrogen storage and peaker developers, would help identify and track current market, technical and regulatory barriers.

Contents

2 Glossary and Abbreviations

2.1 Glossary

Ancillary services	Supporting services to maintain a functional electricity grid.
Brownfield sites	An old industrial or inner-city site that is cleared for a new building development.
Centralised hydrogen storage system	In a centralised system, hydrogen storage facilities, producers and consumers are all connected by a pipeline infrastructure, significantly improving access to cost-effective hydrogen storage.
Cushion gas	Amount of gas required to maintain the pressure and integrity of an underground gas storage facility.
Decentralised hydrogen storage system	In a decentralised hydrogen storage system, storage facilities are isolated from hydrogen networks and are mostly part of point-to-point connections for specific facilities.
Dehydrogenation	Removing hydrogen from a chemical or organic compound.
Electrolytic hydrogen	Producing hydrogen and oxygen molecules from water using electricity.
Energy arbitrage	Purchasing energy during times of low prices for resale at times of higher prices.
Greenfield sites	An area of land that has not been developed previously.
Hydrogenation	Chemically bonding hydrogen and another compound.
Linepack	The gas stored in the transmission and distribution network through changing the pressure of the gas.
Peak shaving	Reducing electricity consumption at times of high demand.
Sedimentary rock	Rock that has formed from deposition of air or water.
Technology Readiness Level	TRL is a method to identify, rate and compare the technical maturity of different technologies, with 1 being the least mature and 9 being the most mature and widely deployed technology.

2.2 Abbreviations

BEIS	Department for Business, Energy & Industrial Strategy
CAES	Compressed Air Energy Storage
CCGT	Combined Cyle Gas Turbine
CCS	Carbon Capture & Storage
CCUS	Carbon Capture, Utilisation & Storage
CHP	Combined Heat and Power
CO_2	Carbon dioxide
DESNZ	Department for Energy Security and Net Zero (formerly known as BEIS)
DLE	Dry Low Emissions
DSR	Demand Side Response
ESO	Electricity System Operator
ETS	Emissions Trading Scheme
FID	Final Investment Decision
FOAK	First of a Kind
GSMR	Gas Safety Management Regulations
HPBM	Hydrogen Production Business Model
HRS	Hydrogen Refuelling Station
LCHS	Low Carbon Hydrogen Standard
LH_2	Liquified hydrogen
LODES	Longer Duration Energy Storage Demonstration Competition
LOHC	Liquid Organic Hydrogen Carrier
LPG	Liquified Petroleum Gas
MCH	Methylcyclohexane
MgH_2	Magnesium Hydrite

MTH	Methylcyclohexane-Toluene-Hydrogen
NH_3	Ammonia
NOAK	Nth of a Kind
NOx	Nitrogen oxides
NSIP	Nationally Significant Infrastructure Project
O&G	Oil and Gas
PE	Polyethylene
PSH	Pumped Storage Hydro
SCR	Selective Catalytic Reduction
SOAK	Second of a Kind
TRL	Technology Readiness Level
UHS	Underground Hydrogen Storage
VRB	Vanadium Redox Battery

Table 1 Summary of energy storage technologies

		Flexibility and whole system benefit					Development	Suitable for Scotland's geography	Technical feasibility	Supply chain	Economics	Sustainability	Policy and regulation
		Short <4 hours	Medium 4-12 hours	Long >12 hours	Seasonal	Export							
Surface storage	Vessel	1	3	3	4	3	1	1	1	2	2	1	1
	Linepack	1	2	3	4	1	2	1	1	3	1	1	1
Underground storage	Salt caverns	3	2	1	2	3	3	4	2	3	1	2	2
	Depleted gas	4	3	1	1	2	2	1	3	3	1	2	2
	Other porous	4	3	1	1	2	3	1	3	3	2	2	2
	Lined rock	1	2	2	3	3	2	1	2	3	3	2	2
Hydrogen carriers	LH_2	4	4	3	2	2	2	1	2	4	3	2	2
	NH_3	4	4	2	2	1	2	1	2	3	2	3	3
	MTH	4	4	3	2	2	2	1	3	4	3	3	3
	MgH_2	4	4	3	2	2	2	1	3	4	3	1	2
Hydrogen peaking plants		1	1	1	1	3	2	3	2	2	2	2	3
Conventional electricity storage	PSH	1	2	3	4	3	3	2	1	2	1	1	3
	CAES	2	2	1	3	3	2	3	2	2	2	1	2
	Li-Ion battery	1	2	3	4	4	1	1	1	3	1	3	2
	Flow battery	1	1	2	3	4	1	1	2	2	2	2	2

1 No concern/ high suitability · 2 Moderate suitability · 3 Limited suitability · 4 High level of concern/ No suitability

3 Introduction

3.1 Context

3.1.1 Energy storage in a net zero energy system

Scotland has an ambitious net zero target of 2045 [1], five years earlier than the rest of the UK. Scotland has enormous potential for renewable energy generation, but network constraints and energy storage challenges are concerns for realising the full potential [2]. Major forms of renewable energy such as wind and solar generate electricity intermittently, while a functional electricity grid needs to balance demand with supply. This creates problems in times of low renewable generation or very high electricity demand.

Intermittency challenges will increase due to Scotland's renewable energy ambitions. In 2022, ScotWind awarded leasing for up to 27.6 GW of offshore wind capacity over the next decade [3]. This is in addition to the target of 20 GW of onshore wind by 2030, up from 8.7 GW installed in 2022 [4]. Other technologies including solar, tidal and wave energy are also expected to play a significant, but smaller role. Figure 2 below shows the challenge of intermittency with electricity demand having regular and predictable peaks and troughs and wind generation varying due to weather conditions.

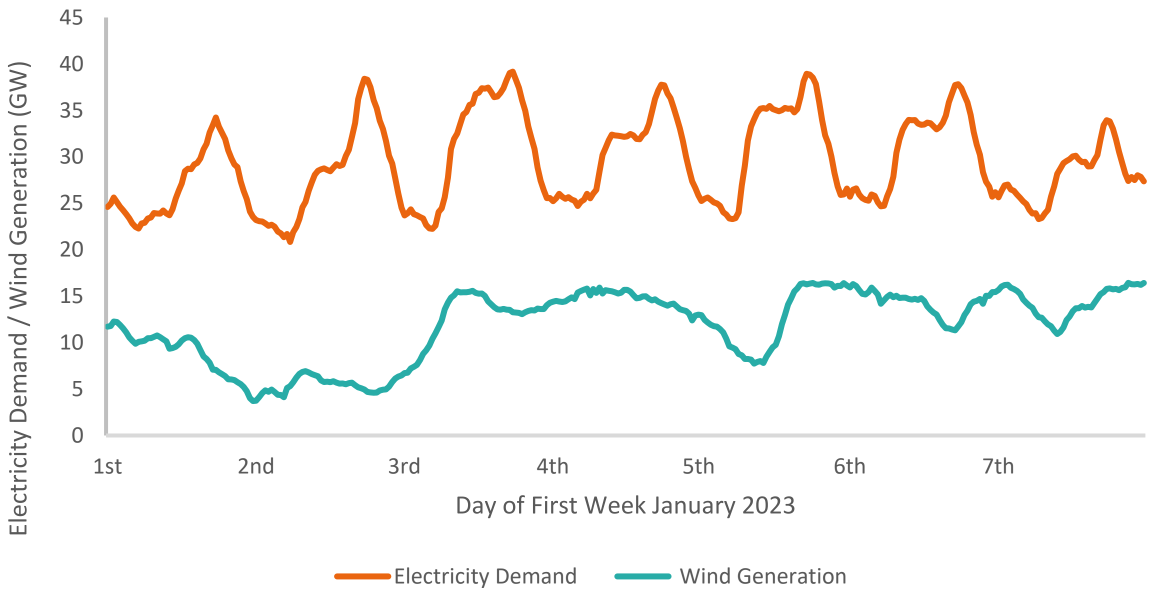

Figure 2 Electricity demand and wind generation in Great Britain for the first week of 2023 [5]

There are several solutions to electricity grid balancing in a world with increasing renewable energy, including Demand Side Response (DSR), interconnectors, flexible power generation and energy storage. DSR involves consumers flexing electricity demand to reflect changes in electricity supply, helping to smooth peaks and troughs in electricity demand. However, this will not solve long periods of excess electricity supply or demand. Interconnectors are electricity cables that connect countries or regions. These projects have long lead times and will not have enough capacity to solve curtailment challenges alone. As interconnectors provide short-term flexibility, they are not the solution for longer periods of low renewable generation. This is because weather systems are generally similar across the North Sea, limiting the electricity export capabilities and import willingness of neighbouring countries [6]. The two submarine cables planned to connect Scotland with England have a combined capacity of 4 GW and will come online in the late 2020s [7].

This leaves energy storage and flexible power generation as key solutions to tackle renewable energy intermittency. Scotland has a large pipeline of energy storage projects with 1.5 GW of pumped hydro awaiting construction and 2.1 GW of battery energy storage with planning permission [8]. However, a broader range of solutions will be necessary to provide enough energy storage capacity to solve the challenge of intermittency (see Figure 7 in section 11.1). A range of energy storage solutions will be required as, for example, batteries are likely to be the most valuable and cost-effective solution for very short duration intra-day storage. They are less suitable, however, for long duration storage such as seasonal storage due to their low discharge duration and high capital costs per unit of capacity.

3.1.2 Intermittency, curtailment and energy storage in Scotland

Curtailment occurs when electricity generators need to reduce their output due to system constraints or a lack of demand. In 2021, wind curtailment in Great Britain amounted to 2.3 TWh with 80% of this taking place in Scotland (see Figure 3) [2]. The challenge of renewable energy curtailment will increase with an increasing share of intermittent renewable generation in the energy mix. National Grid estimate peak annual curtailment in the UK to be more than 40 TWh in all three of its Future Energy Scenarios [9]. Another model suggests that with the current grid reinforcement pace, the UK will not be able to meet renewable energy targets until 2084 [10]. The historic trend of high curtailment in Scotland is likely to continue due to its ambitious plans for renewable energy deployment and network challenges.

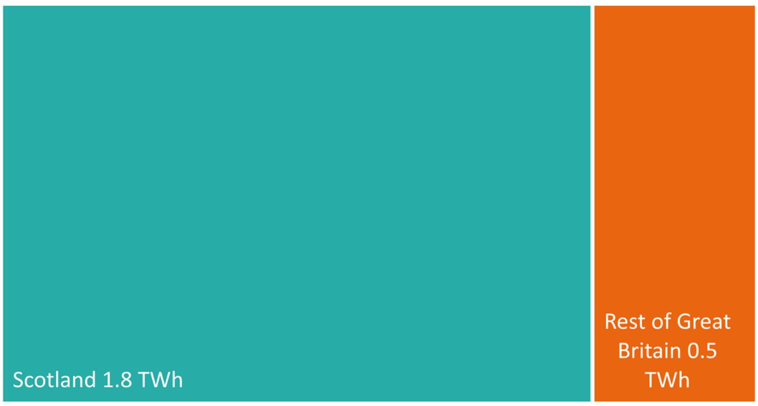

Figure 3 Wind curtailment in Scotland and in the rest of Great Britain in 2021

At times of wind curtailment, fossil fuel peaking power generation needs to be ramped up to balance the grid by compensating for the energy loss. Energy storage can reduce both curtailment and the need for fossil fuel peaking power generation. The two pumped storage hydro (PSH) projects in Scotland can alleviate the problem of intermittency by purchasing the energy that otherwise would be curtailed and discharging it at times of low renewable generation (see section 10). However, their combined capacity of 740 MW [11] [12] is not sufficient to significantly reduce curtailment over long periods of time, highlighting the need for increasing deployment and new solutions.

3.1.3 The potential of hydrogen in Scotland's energy system

Using electricity to produce hydrogen through electrolysis is one option for reducing curtailment of intermittent renewable energy. This hydrogen can then be stored and will be most effectively used in other areas of the energy system where electrification is a less viable decarbonisation route, such as to provide fuel for high temperature industrial processes or heavy vehicles. However, it can also be converted back into power at times when renewable electricity generation is lower than electricity demand. As existing gas-fired power plants can be converted to run on hydrogen relatively rapidly and cost-effectively, large savings can arise when electricity flexibility is met through hydrogen storage and hydrogen power generation [6] [13]. Scotland has ambitions to develop 5 GW of low carbon hydrogen production capacity by 2030 rising to 25 GW by 2045 [3]. These targets sit within the wider context of the UK's 10 GW of low carbon hydrogen by 2030 objective [14].

Hydrogen production in the UK will be subsidised by the UK Government's Hydrogen Production Business Model (HPBM). This will allow producers of hydrogen to make a return while selling hydrogen at a price that matches the natural gas price. In addition to hydrogen production, the HPBM allows for costs of "small scale" hydrogen storage to be included in the support [15]. For larger scale storage, developers will have to wait until the UK Government's design of hydrogen storage business models in 2025 [16].

Hydrogen will be used across a range of sectors, including industry, power, transport and potentially domestic heat. The expected storage requirements for hydrogen in power generation and heat are significant due to the large variation in hydrogen demand.

3.2 Approach

3.2.1 Aims

The aims for our work were to investigate hydrogen storage options and assess their suitability for different durations of storage. We also investigate the potential for hydrogen peaking plants to displace current natural gas peaking plants.

3.2.2 Methodology

This project used a combination of literature review and stakeholder engagement to gather evidence on different forms of energy storage and hydrogen peaking power. Alternative electricity storage technologies are assessed separately in section 10. More information on stakeholder engagement can be found in section 9.

3.2.3 Limitations of our approach

This project has excluded certain forms of energy storage such as thermal storage due to its limited transferability to hydrogen storage. The broad scope of this work has led to some findings being relatively high level. Assessments should continue as the market develops to ensure that information is as up to date as possible. Some technologies assessed are at low technology readiness, therefore more work and trials are needed to qualify the role of these solutions.

4 Aboveground hydrogen storage

Compressed hydrogen vessels, tanks and cylinders are the most wide-spread form of hydrogen storage in the UK and around the world, with their size and pressure varying depending on use case. They are widely used at hydrogen refuelling stations and as buffer storage at production sites. **Linepack capacity** is the gas stored in the transmission and distribution network through changing the pressure of the gas. The storage capacity of the gas network equals the difference between the amount of gas that can be stored at minimum and maximum pressure.

4.1 Flexibility and whole system benefits

Aboveground storage capacity is expected to be limited compared to large-scale underground hydrogen storage. However, relatively fast withdrawal and injection and the ability to buffer short-term and unexpected imbalances promptly makes aboveground storage critical at most parts of the value chain [17]. Alternative short-term electricity storage technologies are assessed in detail in section 10.

Compressed vessels, tanks and cylinders will be crucial in the infancy period of the hydrogen economy. They already support several hydrogen refuelling stations (HRS), producers and industrial end-users in the UK as they have low upfront cost, short lead time and are ideal for small-scale energy storage for up to six hours of discharge (see Figure 6) [18]. This form of storage could allow the withdrawal and injection of hydrogen directly into the transmission network. Small-scale compressed storage has a vital role on the production side. A 50-litre buffer tank can ensure stable pressure in the system, preventing unnecessary ramping up and down of production [19]. However, their overall capacity will be negligible compared to underground hydrogen storage (UHS). Swedish energy analyst AFRY's Central Scenario estimates that medium-pressure tanks will have a combined capacity of 8 GWh, with UHS accounting for 5,220 GWh in 2035 [18].

Linepack capacity is important in mitigating short-term imbalances in existing natural gas networks. Hydrogen storage in the transmission network is expected to have a role of similar importance. However, as the same amount of energy takes up approximately three to four times more space in the form of gaseous hydrogen compared to natural gas, we also expect the transmission system's ability to buffer large swings in hydrogen demand or supply to reduce significantly. Assuming that velocity of hydrogen is roughly three times higher than natural gas, the transmission network is estimated to be able to transport 10-20% less energy as hydrogen [20]. If distribution pipelines are utilised in addition to the transmission network, linepack flexibility would increase [21].

4.2 Development

Compressed vessel storage has a comparative advantage in development compared to linepack storage and large-scale facilities. Given all necessary safety consents are granted, a small-scale compressed system can be ready to be installed without a separate planning permission, unlike large-scale storage. According to trade body Hydrogen UK, the first phase of hydrogen pipeline deployment could take three to four years [22]. This includes routing, design, planning applications and consents, and ordering equipment.

4.3 Technical feasibility

There are multiple types of compressed hydrogen tanks. Vertical tanks can store hydrogen at transmission outlet pressure, which is usually between 50 – 80 bar. There are also high-pressure storage cylinders, capable of storing hydrogen between 300 and 700 bar [23]. Compressed vessel storage is considered mature as they are widely co-located with production facilities and hydrogen refuelling stations. These cylinders, however, can be ten times heavier than the hydrogen within them [24] and the compression to 700 bar is very energy intensive, requiring 13-18% of the energy released during combustion of the hydrogen [25] . This means that approximately 6 kWh of energy is needed to compress one kilogram of hydrogen [26]. Compression to lower pressure, for example to 300 bar, is less energy intense but would require larger storage tanks [27]. To put the energy penalty of 700 bar compression in perspective, it is still three times less energy intensive compared to liquifying hydrogen (see Section 6.3) [25]. Their expected lifetime of 20 years could be affected by corrosion (e.g. metal embrittlement) [24] [28].

Purpose-built pipelines have been storing and transporting hydrogen for decades around the world, especially in the United States (TRL 9). Technology Readiness Level (TRL) is a method to identify, rate and compare the technical maturity of different technologies, with 1 being the least mature and 11 being the most mature and widely deployed technology [29]. While there are only small-scale hydrogen pipelines in the UK, approximately 1,600 miles of pure hydrogen pipelines are operational in the United States [30]. Repurposed pipelines, however, are not as mature (TRL 7) as they have not been deployed at large scale. Further research is needed to understand the technical challenges of repurposing existing pipelines as some pipelines, especially those made from steel, are not suitable for hydrogen transport [31]. This is because pressure variations can lead to fatigue cracking and metal embrittlement [32]. Recent research suggests that operation pressure between 30 and 50 bar may not affect the quality of the pipeline [32]. Metal embrittlement is a challenge of low concern in the UK as steel distribution gas pipes have been being replaced with durable and state-of-the-art polyethylene (PE) for years. While only 62.5% of the gas distribution network has been upgraded with PE pipes by 2023, 90% of the UK mains gas network is estimated to be replaced by 2032 [33].

4.4 Scottish supply chain

Scotland has some capabilities in compressed vessel storage manufacturing [34]. Relevant expertise in valves, heat exchangers, vessels and compressor manufacturing can also be leveraged [35]. Despite Scotland’s relevant compressor manufacturing supply chain in, high-capacity piston and centrifugal compressors, which are needed for hydrogen transmission and storage, are not available on a commercial scale [36]. To put this challenge into perspective, a 100 MW electrolyser would need 50 regular compressors to substitute a high-capacity one [37]. There are further gaps in filling and extraction components, level probes and suspensions [35].

Our high-level research found that there are good capabilities in pipeline installation and manufacture of valves and gaskets [35]. However, Scotland does not have capabilities in manufacturing the pipeline itself and other components (e.g. coating, anodes, sensors) [35]. There are a number of projects running in the UK that are aiming to better understand the technical and commercial feasibility of repurposing pipelines (e.g. Project Union, Hy4Transport project) [38] [39].

4.5 Economics

Compressed vessel storage is very attractive to developers due to low upfront cost. Costs highly depend on the pressure and volume of hydrogen stored, but average storage costs are estimated to be between £0.05 and £0.07 per kWh[1] [40]. The largest share of storage cost is actually in the compression, at approximately £1.54 per kg (£0.037/$kWh_{(LHV)}$)[2] [40]. Recent research suggests that below 65 tonnes of hydrogen (or three days' worth of storage based on the output of a 100MW electrolyser), compressed vessel storage is a lower cost option than liquifying hydrogen and storing it in liquid form [37].

Linepack could be a relatively cost-effective form of hydrogen storage as most of the costs are included in network costs. Hydrogen transmission costs are highly dependent on the distance and the size of the pipeline. Larger 48-inch pipelines can transport a unit of hydrogen more cost-efficiently compared to 20-inch pipelines due to higher transport capacity. Repurposed transmission lines also have cost-advantages over purpose-built networks [36] [42] (see Figure 12 in section 11.3.2).

4.6 Sustainability and safety

Aboveground developments affect the environment through embodied carbon, land-use and high energy demand. Firstly, manufacturing of hydrogen cylinders is currently carbon intensive, requiring steel, carbon fibre and glass fibre [43]. Secondly, as compression takes up a large share of the energy consumption, operators must ensure that their compressors are powered by low carbon energy. Thirdly, new pipeline construction can affect aquatic and terrestrial ecology. Furthermore, if unsuitable material is used for pipelines, embrittlement can lead to hydrogen leakage, offsetting some of hydrogen's environmental benefits [44]. Hydrogen is considered an indirect greenhouse gas as it can increase the lifetime of atmospheric methane. If stringent regulatory requirements were not in place, hydrogen could also pose a safety risk due to high flammability. Whilst the energy required to ignite hydrogen is generally low, the molecule's diffusivity, buoyancy and size require hydrogen to be confined for combustion [45]. The lifetime of hydrogen storage tanks is approximately 10 years [46], whereas hydrogen pipelines can safely operate for 40 years [47].

4.7 Policy and regulatory framework

Compressed vessel storage is going to be subsidised under the HPBM when connected to hydrogen production. Several innovative compressed storage projects have also been funded as part of the Longer Duration Energy Storage Demonstration (LODES) competition [48].

Pipeline developments are expected to be supported as part of the support mechanism of the Hydrogen Transport Business Model. Gas Safety Regulation 1996, however, is currently limiting the concentration of hydrogen in gas networks at 0.1%. The UK Government will make a policy decision in 2023 on whether to allow blending of up to 20% hydrogen by volume into the gas distribution networks [16]. Hydrogen regulation and policy barriers are detailed in section 11.4.

5 Underground hydrogen storage

The most efficient and cost-effective way to store hydrogen at scale is underground. **Salt caverns** are underground stores that can only be built where the geology is suitable. They are created by dissolving a volume of an underground rock salt layer in a process known as leaching. This is the most mature large-scale hydrogen storage technology, with the first UK hydrogen storage salt cavern being constructed in 1972 in Teesside, which is still in operation (see Figure 9 in section 11.2.1). Offshore salt caverns are not considered in this report because they are less mature and have not been trialled anywhere in the world. To date, only one offshore salt cavern project reached concept phase [49]. **Depleted gas fields** can be repurposed for hydrogen storage. These reservoirs do not have to be constructed and can use existing infrastructure. Experience of using depleted gas fields for hydrogen storage is limited to a few pilot studies, such as “Underground Sun Storage” trial in Austria [32], but they are used extensively for commercial natural gas storage. **Other geological formations**, such as saline aquifers, can also be utilised for hydrogen storage, with commercial storage of town gas (~50% hydrogen) in saline aquifers operational over many decades in the 1950s – 70s before natural gas replaced town gas. **Lined rock caverns** provide a suitable short-term storage technology, despite higher capital and operational costs, as they can be hosted in a wide range of ‘hard rock’ geological formations. Alternative electricity storage alternatives, such as pumped storage hydro and compressed air energy storage, are assessed in detail in section 10.

5.1 Flexibility and whole system benefits

All underground hydrogen storage (UHS) types will be a critical part of a wider energy and power system, with each having a different role. Whilst very few large-scale UHS facilities are currently in operation, they will have an increasingly important role in the energy system, with hydrogen estimated to take up 95% of all energy storage requirements in 2030, according to National Grid ESO’s Leading the Way scenario [9] (see Figure 7 in section 11.1).

Salt caverns are the most well-understood hydrogen storage technology currently, with some experts considering it more suitable to support power systems than any other geological storage [50]. It is classified as medium and long-term energy storage, as it is one of the most flexible geological storage types (see Figure 6). This means that salt caverns can go through multiple cycles a year without any significant risk to the integrity of the salt cavern. In terms of capacity, salt caverns take up 15% of global gas storage capacity [51], but they provide over 25% of the gas delivered from storage due to their flexibility [52]. Salt caverns are expected to be utilised when renewable generation is low for multiple days or weeks. As they have long lead time and high system value, several organisations have urged the UK Government to accelerate its progress on the Hydrogen Storage Business Model (see section 5.7). AFRY estimates that a 10-year-long delay in salt cavern developments would increase the level of curtailment in 2035 by 68%. This would result in £1.7 bn in system costs [18]. However, existing salt caverns in the UK have limited capacity, estimated to provide only up to 3 TWh of hydrogen capacity [53]. Due to the limited capacity, long lead times, moderate injection and withdrawal rate of salt caverns and requirement for a hydrogen transmission system, they are not anticipated to meet the UK's seasonal energy storage demand entirely. Scotland does not have adequate geology for salt cavern construction (see Figure 8 in section 11.2.1), meaning that Scottish producers and end-users would have to rely on salt caverns in either England or Northern Ireland. This means that salt caverns require a centralised hydrogen storage system: a pipeline network connecting hydrogen producers, stores and consumers. Before a GB-wide centralised system comes online, only alternative storage technologies can be utilised.

Depleted gas and oil reservoirs are critical in today's energy storage system as they comprise 72% of the global gas storage capacity, with salt caverns and other porous media covering only 15% and 11%, respectively [51].

Our stakeholder engagement suggests that depleted gas fields used for natural gas storage, such as Rough off the North East coast of England, can withdraw gas one day and inject gas the next day. This ability is specific to the geology and depends on the design of the storage site. However, gas reservoirs are generally expected to play a larger role for inter-seasonal energy storage (see Figure 6) as these sedimentary rock basins are significantly less flexible than rock salt. This means that, especially in the early days of the hydrogen economy, depleted gas fields are expected to go through one to two cycles a year [17], supporting the winter power demand of electric heating systems and potentially supporting the increased energy demand of hydrogen heating systems. Therefore, they may have a limited role in providing ancillary services and medium-term storage.

The main advantage of depleted gas fields is the scale they provide. For example, Rough could provide up to 9 TWh of hydrogen storage (see Figure 9 in section 11.2.1). To put this number into perspective, the capacity of an average salt cavern is approximately 0.9 TWh, according to a storage developer. Offshore gas fields close to the Scottish coast, such as the Frigg gas field, could potentially support long-term storage needs of both the UK and mainland Europe. As many European countries have limited gas storage capacity and limited access to large gas reservoirs, more research is needed on competitive advantage in the European large-scale hydrogen storage market. A stakeholder suggested that porous formations in the Central and Northern North Sea areas such as Central Graben, Moray Firth Basin and the Viking Graben have proven seals and, thus have the most potential for large scale hydrogen storage. However, each site will need to be investigated on a case-by-case basis (see details in Section 5.3). Similarly to salt caverns, they can only be utilised after a GB-wide centralised system comes online.

Other porous media refers to deep saline aquifers and onshore geological formations that do not hold natural gas. These geological formations are less flexible than salt caverns and would only go through a very limited number of cycles each year. They have relatively high potential in Scotland especially in the Midland Valley of the Central Belt, with significant amount of Devonian and Carboniferous rock deposits. They comprise thick layers of porous rocks to store the hydrogen and thick sealing impermeable caprocks to prevent any leakage [54].

Due to their limited storage capacity and high capital costs, **lined rock caverns** (LRC) are not yet suitable for long-term, inter-seasonal energy storage, however, they may provide intermediate scale storage opportunities. There are over 200 lined and unlined rock caverns used for gas storage around the world [55]. A lined rock cavern hydrogen storage pilot project has just begun in Sweden and is currently undergoing its first gas tight testing schedule with 100 m^3 of volume. This will be upscaled to 30,000 m^3 on successful results of the commission tests [56]. One advantage of this technology is that it is less geographically constrained than salt caverns or depleted gas fields, meaning that it can offer decentralised storage and support smaller island communities. Although it has small whole system benefits, it is one of the most flexible storage types, being able to inject and withdraw at the same time [57]. In the long-term, they are expected to be deployed at ports, airports and industrial clusters. In the short-term, before a centralised storage system comes online, they will provide a relatively low-cost storage solution to producers and end-users.

Table 2 - Underground hydrogen storage capacity and cycling comparison

	Salt caverns	Depleted gas fields	Other porous media	Lined hard-rock cavern
Annual cycles	Multiple	Few	Few	Multiple
Capacity	Medium	Large	Large	Small

Adapted from IEA (2022) [32]

5.2 Development

Development is crucial to UHS technologies as they typically take three to seven years to develop but can take as long as 10-15 years to come online. This timescale can be lower for existing assets that require repurposing. Multiple factors can slow down development, such as public disapproval, planning and consenting, and the construction itself. The main challenge for salt caverns is the leaching process, which requires developers to dispose of the brine safely, with the resulting produced salts sold to the chemical industry. Building out a brine pipeline infrastructure linking salt caverns to industrial offtakers could also take significant amounts of time. As Scotland does not have adequate geology for salt caverns (see Figure 8 in section 11.2.1), brine disposal pipeline infrastructure is of low concern to

Scottish developers. Whilst porous media do not need any construction or leaching, reviewing each geological formation on a case-by-case basis to avoid any undesired physical, chemical or microbial activity will require time and resources (see Table 11 in section 11.2.2). The opportunity of reutilising historical datasets, existing infrastructure and well sites remains to be the main advantage of depleted gas fields from a development point of view.

Our stakeholder engagement found that positive public perception could be a key enabler of projects in the development phase. This means that if the general public are not provided clear guidance and information on hydrogen sites and the stringent safety requirements they are subject to, residential opposition could delay large as well as small-scale projects.

Table 3 Development opportunities and challenges of underground hydrogen storage technologies

	Salt caverns	Depleted gas fields	Other porous media	Lined hard-rock cavern
Lead time	Seven to eight years (Excluding planning phase) [32] Flushing time for repurposed salt caverns: two to five years [58]	Depending on the geology, development can reach up to ten to twelve years [32]. European projects, however, suggests that development time can be as little as years [59]	Ten to twelve years [32]	Estimated to take less than two years, depending on size[3]
Opportunities	Brine can be used in chemical industry	Existing infrastructure, workforce and expertise. Widely available data on geology	No geographical constraints	No geographical constraints Existing civil engineering and tunnelling workforces and skills can leveraged
Challenges	Drilling and leaching requires infrastructure for brine. Environmental campaigns may lengthen development time	Every geological formation has to be checked on a case-by-case basis to avoid leakage and undesirable chemical and microbial activities.		Little experience with 100% hydrogen lined rock caverns High upfront cost compared to aboveground storage Construction involves blasting that may disturb locals

5.3 Technical feasibility

We have identified technical opportunities and challenges for all UHS technology, with most of our research relying on theoretical studies and modelling. With very few commercial or pilot projects currently in operation yet, hydrogen storage trials are increasingly needed to gain deeper and more accurate insight. **Salt caverns** (TRL 9) are the most well-understood hydrogen storage technology, with multiple hydrogen stores currently operational. These stores, however, have been developed for industrial use and designed for low-cyclic use [17]. There is now a requirement for research efforts to investigate how fast cycling of hydrogen affects the cavern and well integrity. Although microbial and chemical activities pose less risk in salt caverns, the extent to which processes could contribute to hydrogen contamination and loss are currently being studied, with increasing need for more trials. **Depleted gas fields** (TRL 3-4), on the other hand, are less well-understood for storing hydrogen. Anecdotal evidence suggests that when town gas (50% hydrogen) was stored in depleted gas fields some hydrogen was lost and contamination occurred, but not enough to stop the commercial operations[1]. More advanced technology today suggests recovery rates could be almost 90% [60]. Although more microbial, physical and geochemical risks have to be mitigated in porous media, recent research and computer modelling suggests that they can all be addressed [61] [62] (see Table 11 in section 11.2.2). Depleted oil fields, on the other hand, are not likely to be targets for hydrogen storage as there is uncertainty on how hydrogen, crude oil and other gases would interact in the reservoir. Most hydrocarbon fields in the Northern North Sea are oil and condensate fields, with a few but large gas fields on the boundary between the UK and Norway, such as the Frigg gas field. Aquifers and **other porous media** (TRL 2-3) face similar technical challenges, but in contrast to gas reservoirs, there is significantly less modern seismic and well data, leading to more uncertainty. Whereas depleted gas fields have been proven to seal natural gas adequately, other geological formations are not necessarily tight enough for hydrogen storage. **Lined rock caverns** (TRL 5) are more well-understood, but due to the low number of pure hydrogen trials, there is some uncertainty around their commercial deployment (see summary in Table 11 in section 11.2.2).

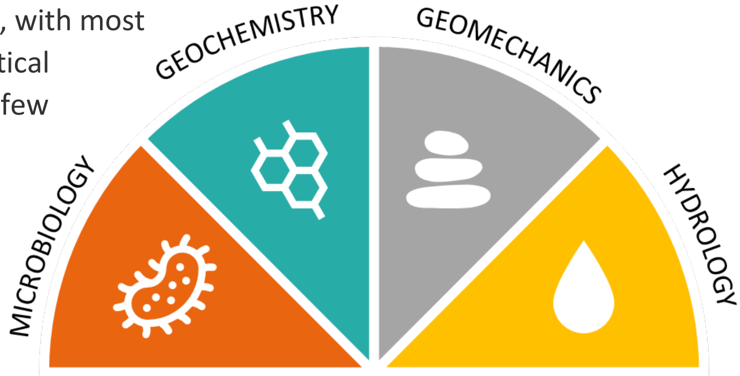

Figure 4 Underground hydrogen storage developments face microbiological, geochemical, geomechanical and hydrological challenges

[1] This consumption and contamination was primarily due to the fact that town gas contains significant quantities of methane, carbon dioxide and carbon monoxide, all of which are reactive gasses, and it is expected that storage of pure unreactive hydrogen will not result in significant losses or contamination, especially if the storage sites are carefully selected to reduce these risks.

5.4 Scottish supply chain

Underground hydrogen storage is likely to require similar skills to the oil and gas (O&G) sector. Scotland's more than 45 years of experience in O&G puts it in an advantageous position. With more than 75,600 jobs in O&G and an existing supply chain [63], there are considerable opportunities for Scotland. A recent study suggests that 90% of the O&G workforce have medium to high skill transferability and are well placed to work in the hydrogen or CCUS sectors [64]. Scotland's world-leading academic research, market for engineering design, tunnelling workforces and skills, experience in procurement and commissioning activities could be leveraged to exploit training opportunities [34] [65].

There are also supply chain gaps and opportunities to consider. The Hydrogen Sectoral Action Plan found that compressor packages will be a significant proportion of the value of storage projects and while the UK has highly relevant expertise, this is in small-scale compressor manufacturing [66]. Although these compressors are not suitable for large-scale hydrogen storage, existing Scottish expertise and value chain in this field can be leveraged to meet the current shortage of high-capacity compressors (see Table 12 in section 11.2.3).

5.5 Economics

The economics of underground hydrogen storage is highly favourable, especially at large-scale and in the long-term. In terms of MWh, **depleted gas fields** are expected to be the lowest cost options due to the existing infrastructure and high capacity. The levelized costs for hydrogen storage in depleted reservoirs are estimated to be around £0.97 per kg (£0.029/$kWh_{(LHV)}$)[4], with **salt caverns** costing approximately £1.28 per kg (£0.038/$kWh_{(LHV)}$)[5] [67]. Salt caverns have higher cost in terms of MWh due to the need for construction and lower average capacity. However, they are still estimated to be more than twenty times cheaper than compressed vessel storage [18]. It is also more cost-effective to store hydrogen in deeper salt strata as the geology allows higher working gas capacity [68]. No reliable and precise cost estimations have been carried out for **other porous media**, but they are expected to be more expensive than depleted gas fields due to thorough geological investigation and infrastructure needs, along with the economic risk of working and cushion gas loss. **Lined rock caverns** are currently the most expensive UHS technology, but they are anticipated to undergo significant cost reductions when the technology is deployed at a large scale (>3000 tonnes of hydrogen) [69].

Researchers at Imperial College London estimate that underground hydrogen storage is currently only cost-competitive above 300 hours of discharge. However, by 2040, hydrogen is anticipated to be the most cost-effective energy storage technology above 16-64 hours of discharge (depending on the discharge rate) [70] (see Figure 10 and Figure 11 in section 11.2.4). Stakeholders suggest that operators' economic incentive is to run their facilities through as many cycles as possible as frequent cycling generates the most revenue. Therefore, any future market framework and market mechanism needs to ensure that seasonal storage, operating only a few cycles a year, is economically attractive to operators.

5.6 Sustainability and safety

Overall, all underground hydrogen technologies have environmentally positive impacts as they enable the cost-effective decarbonisation of the energy system. However, there are certain environmental risks that needs to be addressed in order to maximise this benefit. During construction of salt caverns, it is important to dispose of brine, the by-product of leaching, in an environmentally sustainable way. This is because it can cause serious environmental damage in fresh and salt water [71] [72] [73]. As brine can be used as feedstock in the chemical industry, it is important that industry collaboration is maintained. Furthermore, the compression of hydrogen accounts for a considerable share of the energy consumption of UHS facilities. To minimise the carbon footprint of hydrogen storage, compressors should be powered by low carbon energy.

There are also some environmental concerns directly associated with the chemical and physical properties of hydrogen. For example, hydrogen injection and withdrawal will have to be carried out with care to avoid seismic risks. [74] [61] [75]. If stringent regulatory requirements were not in place, hydrogen could also pose safety risk due to high flammability. Whilst the energy required to ignite hydrogen is generally low, the molecule's diffusivity, buoyancy and size require hydrogen to be confined for combustion [45].

To maximise the benefits of hydrogen production, storage and end-use, regulation must minimise fugitive hydrogen emissions, which can partially offset its environmental benefits in the atmosphere [44]. As salt caverns have been proven to be airtight, hydrogen leakage is of a higher concern for porous media. Whilst comprehensive computer modelling suggests that leakage through caprock will be very limited [61] [62], depleted gas fields pilot projects are needed to better understand this risk. UKRI and the UK Government are funding the Environmental Response to Hydrogen Emissions Research Programme [76] to address some of these knowledge gaps. However, to fully understand the environmental impact of UHS, a national baseline environmental study is needed [77].

5.7 Policy and regulatory framework

To mitigate current market barriers, the UK Government will design a hydrogen storage business model by 2025 [16]. The support mechanism is expected to be technology neutral and support all types of geological storage technologies. Our stakeholder engagement found that policy barriers include but are not limited to:

- Lack of interim measures before the 2025 design of the Hydrogen Storage Business Model.
- Lack of concise and hydrogen-specific regulatory framework.
- Use of carbon dioxide as cushion gas is not permitted under current regulatory framework.
- Hydrogen producers supported under the Hydrogen Production Business Model cannot sell their products to intermediaries.
- Delays and lack of clarity around planning and consenting.

In addition to these regulatory and policy barriers, some stakeholders suggested that the support mechanisms for interconnectors and renewable generation distort the market for flexibility and discourage energy storage and hydrogen projects. Regulatory barriers are detailed in section 11.4.

The UK and Scottish Governments are supporting UHS technologies through various funding streams. These include the UK Government' s Hydrogen Production and Storage Business Models, the UK Government's Net Zero Hydrogen Fund, the Scottish Government's Hydrogen Innovation Scheme and Innovate UK (further detailed in section 11.2.5).

6 Liquid hydrogen and carriers

A range of technologies are available to increase the volumetric energy density of hydrogen for easier long-distance transport and storage. At a very low temperature, gaseous hydrogen can be turned into **liquid hydrogen**. Liquification can help with storing hydrogen in smaller spaces for longer periods of time, transporting it and using at as aviation or shipping fuel. Hydrogen can also be reacted with nitrogen at high temperature and pressure to produce **ammonia**. Ammonia can be stored more easily, and its volumetric energy density is also higher than hydrogen. When transported to its destination, ammonia can be cracked back into hydrogen and nitrogen. **Liquid Organic Hydrogen Carriers** (LOHC) absorb hydrogen in an organic compound. We focus on the most advanced organic carrier, methylcyclohexane, which can be easily broken down to hydrogen and toluene. Lastly, **metal hydrides**, like magnesium hydride, can carry hydrogen in a solid state, making international trade safer and simpler.

6.1 Flexibility and whole system benefits

Ammonia is generally produced by the Haber-Bosch reaction. This process combines three hydrogen molecules (3 H_2) and a nitrogen molecule (N_2) to form two molecules of ammonia (2 NH_3). In the past, ammonia production has been inflexible, running 24 hours a day and seven days a week. This is because of the relatively steady state required for the Haber-Bosch process. However, with the requirements for green ammonia production from intermittent renewable energy, new ammonia production processes are being developed [78] [79]. Alternatively, a hydrogen buffer, for example a pressure vessel or line rock cavern, can be used to provide a more consistent stream of hydrogen [80]. Due to limited experience with electrolytic ammonia production and need for hydrogen storage, ammonia provides less flexibility advantages than other storage solutions. In the future, ammonia could have a role in system flexibility if production becomes more flexible or if it is used with hydrogen storage as a buffer. Its role will depend on the international export market for ammonia or ammonia power generation developing in the UK.

In theory, producing hydrogen and conversion to liquid form could cut curtailment and provide system benefits. However, **liquified hydrogen** (LH_2) has high costs due to the requirements for extremely low temperatures (-253°C). The main benefit of liquid hydrogen is its higher density at low pressure than gaseous hydrogen. For stationary storage, the energy losses from cooling and risk of boil off are likely to outweigh the higher energy density that liquifying hydrogen provides. There could be some but limited opportunity for liquid hydrogen to reduce curtailment costs if Scotland exports liquid hydrogen or liquid hydrogen becomes widely used in aviation and/or shipping.

As with ammonia, historical production of **Liquid Organic Hydrogen Carriers** (LOHCs) has been low and consistent, reflecting the requirements of industrial users. However, flexible LOHC production technologies are more mature than flexible ammonia production [81].

Metal hydrides are expected have a similar role to LOHCs as production can also ramp up and down relatively flexibly. After being converted to hydrogen, magnesium from the metal hydride does not necessarily need to be returned to the original conversion point as it can be used as feedstock in industry. Therefore, the role of LOHCs and metal hydrides in power system flexibility in Scotland will depend on technology development, the market for these compounds and volumes of trade.

6.2 Development

The development phase of LH_2 and hydrogen carrier facilities is longer and more complex compared to conventional electricity and gas storage technologies. This is because they require extensive support infrastructure at each point of the value chain. Hydrogenation, transport, storage and dehydrogenation infrastructures are key enablers of all conditioning systems.

Scotland already has existing ammonia production capacity that can be leveraged for upscaling. Developing liquifying and hydrogeneration plants will, however, require more resources and time. Transport and storage infrastructure is critical for the upscaling of ammonia, LH_2, LOHC and metal hydride trade. However, Scotland has very limited existing infrastructure for these technologies.

Several Scottish ports have been identified as highly suitable for international hydrogen trade, such as Grangemouth, St Fergus and Cromarty Firth [35]. However, they all need significant infrastructure investment to unlock large-scale hydrogen trade. Industry experience with LNG infrastructure suggests that liquefied hydrogen import/export terminals will need three to four years to be built [36]. Planning, consenting, and the feasibility study phase could add a further eight years to the lead time [36]. We expect the construction time of ammonia tankers to be similar to liquified petroleum gas (LPG) tankers. This means that tankers could be ready to ship ammonia one year after they are ordered [36]. With respect to liquid hydrogen tankers, we expect the development time to be between two to four years as the technology is fairly similar to LNG tankers [36]. However, increased demand for tankers and shipyard capacity could lengthen required lead times. With respect to LOHC and metal hydrides, they are already compatible with existing liquid fuel pipelines and vessels, decreasing the cost and the lead time of infrastructure construction.

6.3 Technical feasibility

Ammonia is currently widely used and can be stored as a liquid due to its comparably low boiling point of -33.4°C. Ammonia storage as a liquid avoids some of the high costs in compression and storage tanks of gaseous fuels. It also significantly increases the energy density of ammonia in comparison to hydrogen. Liquid ammonia has over 50 % more volumetric energy than liquid hydrogen and more than twice the volumetric energy of hydrogen gas at 700 bar (see Table 14 in section 11.3.1) [82]. There are also pre-established supply chains and shipping ammonia is likely to have a higher technical feasibility due to its similarities to LPG [35].

While producing ammonia from fossil fuels is a mature technology, low emission ammonia production and use is less developed. Ammonia can be used directly, with options for combustion currently being explored. Technological improvements are required to improve efficiency and reduce costs and nitrogen oxide (NOx) emissions of ammonia combustion. Alternatively, ammonia can be “cracked” back into hydrogen. Innovative projects are currently developing solutions to reduce costs and improve efficiencies of this process [82] [83] [84].

Conversion and storage of **liquid hydrogen** is technically feasible. However, there are significant engineering challenges due to the need for temperatures below -253°C. Boil off can create losses, however, these can be minimised by vacuum walls of storage vessels and reducing the surface area to volume ratio. In large scale spherical tanks, boil off could be limited to less than 0.1% per day [85]. Liquefying 1 kilogram of hydrogen requires approximately 12.5-15 kWh [86], consuming the equivalent of 30%-40% of the energy content of the hydrogen on average [27] [87]. With increased economies of scale and technology improvements, this could be reduced to 18% [88].

As **methylcyclohexane-toluene-hydrogen (MTH) systems** are not deployed on commercial scale, there is some level of uncertainty around the system’s round-trip efficiency and technical barriers. The hydrogeneration process, during which toluene is reacted with hydrogen to form methylcyclohexane, is highly exothermic. This means that MTH production emits substantial amount of heat, providing good opportunity for heat recovery. On the other hand, dehydrogenation, recovering hydrogen from methylcyclohexane (MCH) is endothermic, requiring substantial amount of heat. Therefore, the efficiency of the system highly depends on how much heat can be recovered. The main technical advantage of MTH systems is that these compounds can be transported and stored at ambient temperature and pressure.

Current **magnesium hydride** production in the UK is limited and future potential is largely unknown. A magnesium hydride developer estimates that approximately 10.3 kWh is needed for hydrogenation and dehydrogenation of 1 kg of hydrogen, making the technology relatively competitive with other hydrogen carriers (12.5-15 kWh for liquifying hydrogen and 14-19 kWh for ammonia conversion and reconversion [86]). The main benefit of magnesium hydride is that its production is simple. No catalyst or purification equipment is needed (in contrast to ammonia and LOHC; see Table 14 in section 11.3.1) and conversion can be made at relatively low temperature (350°C), some of which can be recovered. Magnesium hydride is highly reactive and must be suspended in oil. Therefore, any water and oxygen would need to be removed from the hydrogen prior to conversion.

6.4 Scottish supply chain

Ammonia production is highly mature with multiple sites across the UK and Scotland. These facilities, however, are integrated with high-carbon hydrogen production, such as natural gas reformation, oil reformation or coal gasification. This means that there is less experience working with electrolytic or shipped hydrogen. The supply chain for ammonia cracking and shipping is not mature in Scotland [35]. A few projects are currently testing the concept of ammonia cracking, for example the Ammogen consortium, AFC Energy and Eneus Energy on the Orkney Islands.

Scotland has very limited capacity in liquifying hydrogen and no experience in large-scale shipping. There is some experience in manufacturing in certain parts of the supply chain, for example heat exchangers and compressors. However, LH_2 supply chain consists of multiple areas including, but not limited to, cooling systems, filters, reactors, condensers, evaporators, separators, circulators, expanders/companders, blowers and absorbers [35].

There is currently no LOHC production, transport and storage in the UK on a commercial scale [89]. As toluene is used for benzene manufacturing, there are a few suppliers present in the Scottish market [90]. Production, however, along with methylcyclohexane manufacturing, would need to be significantly upscaled. A recent LOHC feasibility study suggests that the UK is at risk of having to rely on the toluene supply of other countries given substantial gaps in the supply chain [89]. Nevertheless, an increasing number of companies are interested in developing a large-scale MTH system in the UK, such as Greenergy and the Germany-based Hydrogenious [91]. The Net Zero Technology Centre and ERM are also researching the feasibility of LOHC transport between Scotland and Rotterdam.

There has been no research conducted on the supply chain requirements of magnesium hydride production and transport. Its simplicity, however, suggests that few bottlenecks are expected once the technology is scaled up. One of these bottlenecks is the lack of primary magnesium production, which could make the UK overly dependent on imports from other countries [92]. It estimated that China produces 82% of magnesium globally and provides more than 90% of the European Union’s primary magnesium [93]. US researchers have found a way to extract magnesium salt from sea water, but this technology is not yet deployed on a commercial scale [94].

While there are substantial gaps in the Scottish supply chain, there are also opportunities that could be leveraged. Existing Scottish Ports can be repurposed to support international hydrogen trade [35] (see section 6.2).

6.5 Economics

The key economic challenge of hydrogen carrier technologies is the low roundtrip efficiency. This results in high costs per unit of energy stored. The main advantage of hydrogen carriers is the higher energy density per unit mass than gaseous hydrogen, reducing costs of long-distance transport. However, for applications within Scotland the low roundtrip efficiency compared to gaseous forms of hydrogen storage are likely to make hydrogenation prohibitively expensive.

Table 4 Potential hydrogen import costs

	Liquified H_2	Ammonia	LOHC
Conversion	£9-10 per MWh	£9-11 per MWh	£6-7 per MWh
Shipping	£6 per MWh	£2 per MWh	£3 per MWh
Reconversion	£5 per MWh	£7 per MWh	£9 per MWh
Price in the UK	£35-47 per MWh	£25-39 per MWh (ammonia) or £34-45 per MWh (hydrogen)	£33-44 per MWh

Source: The CCC [95]

Future costs associated with hydrogen carrier technologies are uncertain as none of them have been deployed on a commercial scale. BloombergNEF suggest that that exporting hydrogen could cost at least £1 per kilogram (3p per $kWh_{(LHV)}$) as ammonia, £2.2 per kilogram (6.6p per $kWh_{(LHV)}$) as liquified hydrogen and £2.3 per kilogram (6.9p/$kWh_{(LHV)}$) as LOHC [35]. Economic predictions are highly variable, but they are consistent in identifying **ammonia** as potentially the lowest cost technology for long-distance transport. Shipping hydrogen as ammonia has a clear comparative advantage if it is directly used as feedstock at the point of end-use because there are no further reconversion costs [96]. **Liquified hydrogen** is estimated to be more expensive than ammonia due to the high energy consumption of the liquefaction process (10-15 kWh per kilogram) [37]. However, recent theoretical modelling found that above 65 tonnes, it is still more cost effective to store hydrogen in liquid form compared to pressurised vessels as larger volumes can be stored in a single tank [37]. Cost estimations for **LOHC** production, transport and dehydrogenation vary widely, with most models suggesting that it could be competitive with LH_2 but not with ammonia [97] [95]. This comparative disadvantage is reflected in the low number of LOHC projects announced to date [98]. Lastly, no extensive research has been carried out on the economics of **magnesium hydride**, but initial modelling suggests that its CAPEX would be around £52 per kilogram of hydrogen storage[6] (in comparison to £790 per kilogram for compressed vessels[7]). According to a magnesium hydride developer, it would add approximately £0.12-0.5per kilogram[8] to the assumed hydrogen price of £1.6 per kilogram, depending on the transport distance and the amount of stored hydrogen.

6.6 Sustainability and safety

Ammonia, like many other hydrogen derivatives, can rapidly scale up decarbonisation. However, there are environmental risks associated with its production, transport and end-use that need to be taken into consideration. Firstly, ammonia is a toxic gas, meaning that exposure to high levels may cause burns in the airways and can be fatal [99]. If an ammonia spill were to occur, it could also damage aquatic environments and associated ecological receptors [100]. It is a generally a non-flammable gas, but if it is mixed with air and ignited at high concentration, it could explode. As ammonia is a corrosive gas, additional measures and extra care are needed to avoid leaks [101]. Lastly, the compression and conversion are energy intensive processes. The Haber-Bosch process accounts for approximately one third of the energy demand of ammonia production [101]. As most of these Haber-Bosch reactors need high temperature and pressure and are powered by fossil fuels, the electrification of the Haber-Bosch process is urgently needed [82] [102].

Energy consumption is the main concern for **liquified hydrogen**. Hydrogen liquefaction is very energy intensive and commercially available hydrogen liquefaction technologies require up to 40% of the energy equivalent to the energy content [27]. Liquefaction and regasification, especially the precooling phase, may also require natural gas, increasing the carbon emissions of hydrogen [103] [104].

There are environmental concerns associated with **MTH systems** as well as both methylcyclohexane and toluene being environmentally hazardous. This means that a potential spill could severely damage aquatic ecosystems [105]. As toluene is produced during oil refining, it is relatively greenhouse gas intensive [106]. Therefore, reusing the same toluene for multiple hydrogen transports is critical from a lifecycle emission point of view. Methylcyclohexane and toluene are also flammable, requiring additional fire safety measures [17].

MgH_2 is not toxic, but it is flammable and highly reactive with oxygen and water. However, if MgH_2 is suspended in oil, it is safe to store and transport. In case of a spill, oil-suspended magnesium hydride can be easily cleaned up and would not damage the aquatic ecosystem. Although magnesium can be reused for magnesium hydride production, magnesium needs to be produced sustainably in the first place. The current production method involves dolomite calcination and reduction, which is greenhouse gas intensive [107].

A recurring environmental challenge for all hydrogen carrier technologies is that the conversion process is energy and greenhouse gas intensive. The carbon footprint of these technologies, however, is expected to reduce as the electricity grid decarbonises and low carbon technologies and fuels become commercially available [104].

6.7 Policy and regulatory framework

There is no specific policy support for hydrogen conditioning systems and solid-state technologies other than innovation funds, like the Scottish Government’s Hydrogen Innovation Scheme [108]. All ammonia, liquid hydrogen and LOHC projects would have to comply with COMAH or Hazardous Substance Consent, except for magnesium hydride.

Further information on currently funded projects and hydrogen specific regulation can be found in sections 11.3.4 and 11.4, respectively.

7 Hydrogen peaking plants

The UK electricity system is extremely variable and therefore needs to contain reliable sources of dispatchable electricity generation that can react rapidly and operate flexibly. 'Peaking' plants address this need; they are highly flexible electricity generators that do not routinely operate but are ready to do so when needed at times of peak demand or low generation.

Power generation in the UK is dispatched in order based on cost (or 'merit'). The cost of a dispatching a particular generator is set by a combination of its fuel prices, emissions charges, plant efficiency, start-up times, required profit margins, and other general running costs. After renewables, the lowest cost units, known as baseload units (i.e., nuclear), run as much as technically possible, whilst mid-merit units (i.e., high-efficiency combined-cycle gas plants) can typically operate thousands of hours per year.

Although there is no formal definition, peaking plants in the UK tend to be low-efficiency open-cycle gas plants and have generally operated for no more than 5% (or 450 hours) of the year [109]. The typical number of hours of operation however is likely to increase in a future electricity system due to the more variable generation from an increasing proportion of renewable generators.

Hydrogen is one of the potential alternative technologies that peaking plants could adopt economically to address the ongoing need for peaking generation, whilst also allowing such plants to decarbonise. These are likely to have similar characteristics to existing gas turbines [50], meaning that it is possible and may be more cost-effective to retrofit existing plants, rather than requiring new builds.

7.1 Flexibility and whole-system benefits

Supply-side electricity flexibility can be offered by a range of solutions such as batteries, interconnectors, and dispatchable power. There are two main options being considered currently for low carbon dispatchable power: hydrogen-fired turbines and gas turbines with carbon capture and storage (CCS). Despite lower capital costs for hydrogen-fired plant, higher cost of hydrogen relative to natural gas will result in CCS-enabled gas plant dispatching ahead of it in the merit order, failing some form of Government subsidy or intervention. The majority of modelling agrees with this, suggesting that hydrogen is only likely to be lower cost than gas CCS for low load-factor peaking generation sites [50] [110] [111].

These dispatchable power generation options can react relatively quickly to signals that an increase in electricity generation is required to meet demand. The reaction speed depends on the scale and type of turbine. Current gas peaking power has a startup time of 0.5-15 minutes with larger CCGTs and CHPs having a startup time of 30-60 minutes [110].

A major concern regarding the increasing penetration of renewable electricity is large-scale, long-duration energy storage. Historically, hydrocarbon fuels such as coal and gas have been stored in vast quantities to accommodate for seasonal fluctuations in energy supply and demand. With increasing electrification, especially in domestic heat, and increased penetration of renewable energy, the potential shortfall between instantaneous supply and demand could grow significantly, particularly in the winter months when heat demand peaks and renewable output drops. As a result, the energy system will require large amounts of low-carbon dispatchable power, which in turn will require large amounts of long-term energy storage in order to operate reliably as and when needed.

The large scale of storage provided by hydrogen allows for continued electricity supply during these sustained periods of low renewable energy. Whilst batteries and other forms of electricity storage will typically deplete over a period of hours or days, large-scale geological hydrogen stores, and subsequent conversion back to electricity, can provide long-term resilience for weeks or months. In AFRY's energy system model, the largest system savings occur when hydrogen storage and hydrogen CCGTs are deployed for long-term flexibility [6].

7.2 Development

The development of hydrogen peaking turbines is likely to be similar to that of current gas turbines (Figure 5). Lead times may be longer for First-of-a-Kind (FOAK) and Second-of-a-Kind (SOAK) projects due to the new nature of these developments. However, once Nth-of-a-Kind (NOAK) projects are reached, lead times are expected to be comparable [111].

Our stakeholder engagement suggests that positive public perception could minimise delays to developments. To avoid residential opposition, residents living near hydrogen power plants need be provided clear information on hydrogen combustion, its role in the net zero transition and the stringent safety requirements it is subject to.

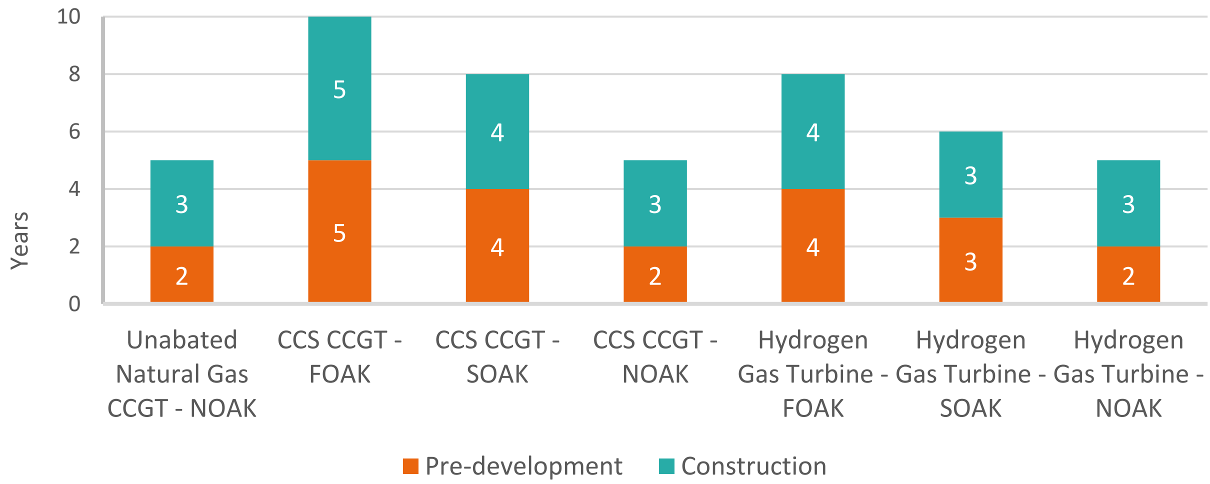

Figure 5 Natural gas and hydrogen turbine lead times (adapted from HyImpact Series [111])

7.3 Technical feasibility

There have been turbines, located around the world, operating on blends of natural gas and hydrogen in operation for decades, with millions of hours of cumulative operation [112] [113]. However, operation of 100% hydrogen turbines has been limited to date.

Whilst pre-mixed burners have been the industry standard for many years in natural gas turbines, they have to undergo fundamental redesigns to accommodate 100% hydrogen due to hydrogen's higher flame speed and temperature. Higher flame speeds can result in dangerous combustion phenomena such as flashback, whilst higher flame temperatures lead to excessive NOx formation [114]. As a result, most existing pre-mixed Dry Low Emissions (DLE) burners are currently only rated to burn hydrogen blends in the range of 10-30% for heavy-duty power applications (approx. >100MW) [115].

Whilst high-blend or 100% hydrogen combustion in heavy-duty turbines is technically feasible provided there is sufficient NOx abatement, the most cost-effective way to do so is through careful combustion system design. However, such technology is still some years away from commercial availability [116]. Other options to achieve this are either by using specially designed burners with external fluid injection (i.e., water, steam, or nitrogen) or through post-combustion techniques such as Selective Catalytic Reduction (SCR), both of which are costly and often not considered economically attractive [115].

There is some evidence of 100% hydrogen use in small-scale combined heat and power (CHP) operations [117], an example of which is 2G's CHP engine at Kirkwall Airport. These can have a relatively quick start up time of five-ten minutes but are currently small in scale at less than 1MW.

Large scale turbines for peaking power plants are currently being developed by established turbine manufacturers around the world. These are expected to be available in the late 2020s to early 2030s [116] [118].

Hydrogen power generation may also require larger diameter pipework due to hydrogen's lower volumetric density than natural gas. In select cases, hydrogen also presents material challenges to retrofit of existing pipework due to its small particle size and high permeability. Hydrogen atoms can diffuse into certain metals and react, causing embrittlement, though this can be mitigated through appropriate material selection and / or application of protective coatings [119].

7.4 Scottish supply chain

Large turbine manufacturers are generally located outside of Scotland. However, some of the engineering skills required for hydrogen peaking power may be easily transferrable from Scotland's O&G sector.

There is currently only one operational large-scale natural gas fired power plant in Scotland, Peterhead Power Station in Aberdeenshire. This is a combined cycle gas turbine (CCGT), with a capacity of 1,180MW. There are a multitude of small-scale electricity generation sites in Scotland including nine diesel generation sites in the North of Scotland SSE licence area. These are located on remote Scottish Islands and are used for backup supply [120].

The skills for fossil fuel power generation are likely to be transferable to hydrogen power generation with some retraining due to the different chemical and physical properties of hydrogen. More generally, around 90% of the O&G workforce could be transferred to the hydrogen and CCUS sectors with some retraining [64]. Existing experience with hydrogen power generation, like the hydrogen CHP operating at Kirkwall Airport in Orkney, could potentially aid and accelerate the learning and retraining process.

7.5 Economics

When hydrogen peaking power matures as a technology, the costs of infrastructure are expected to be similar to costs of natural gas peaking power today. Early projects will face higher infrastructure costs due to less experience and scale.

Without policy support, the fuel costs faced by hydrogen peaking power operators would be significantly greater than historic natural gas prices. The economics of hydrogen peaking power depend on policy development. In a scenario with no policy support, hydrogen is more expensive than fossil fuels. However, measures such as production support and carbon pricing make it more financially attractive.

It is expected that large scale hydrogen peaking plants will have a capital cost in the range of £350-600/kW [111] [110]. The cost of electricity produced will depend on the annual hours of operation. If operating at a reasonably high load factor of 25-45%, costs could be £90-125/MWh for new build and £65-100/MWh for retrofit turbines [18] [50]. Hydrogen is most competitive with alternatives at lower load factors. It is expected to be the cheapest form of flexible electricity generation for plants with a load factor below 20-30% [110] [18]. This is due to lower capital costs but higher fuel costs than alternatives such as gas CCS without subsidies. Aurora Energy Research estimates that replacing natural gas power plants with hydrogen power generators could save up to £90 bn compared to relying on short-term energy storage for flexibility [13].

7.6 Sustainability and safety

The combustion of hydrogen produces heat and water, with no direct greenhouse gas emissions or the carbon monoxide typically associated with fossil-fuel power generation. However, due to the higher combustion temperatures, hydrogen power generation would have higher NOx emissions than natural gas if not addressed during the flame design. This is easily achieved with one solution to NOx emissions being a larger or more efficient Selective Catalytic Reduction (SCR) [119].

There may also be emissions associated in the production or supply of hydrogen. These will depend on the hydrogen production and transportation method.

7.7 Policy and regulatory framework

The Department of Energy Security and Net Zero (DESNZ) is currently investigating the need for market intervention in hydrogen to power. DESNZ has commissioned a study to assess the financial need for market intervention and potential business model design options [121].

In addition, two ongoing policy amendments are very likely to increase the prevalence of hydrogen in the power sector. Firstly, 'Decarbonisation Readiness' measures may eventually require all thermal power stations to prove that they possess a viable pathway to achieving decarbonisation through conversion to either 100% hydrogen or gas CCS [122]. Secondly, amendments to the Capacity Market, the primary financial mechanism through which peaking plants operate, may introduce more stringent emissions limits that will invariably promote decarbonisation through hydrogen or CCS [123].

There are several other policy measures in place relevant to hydrogen power generation:

- The HPBM provides revenue support to hydrogen producers across the UK. Scotland was the region with the highest number of shortlisted electrolytic projects in HAR1. DESNZ is also considering incentivising and rewarding developers that deliver wider system benefits by locating their production in a beneficial area for electricity network constraints, like Scotland [124].
- The Low Carbon Hydrogen Standard (LCHS) ensures that hydrogen production that receives government support meets a minimum emissions threshold.
- The UK Emissions Trading Scheme (UK ETS) applies a carbon price to greenhouse gas-emitting power generators which hydrogen power will compete with.
- The Review of Electricity Market Arrangements (REMA) sets out a series of options for reforming the British electricity market in response to increased deployment of intermittent renewables. For example, zonal or nodal markets would mean that price signals could encourage large offtakers to situate in areas of grid constraints or large generators would be further encouraged to situate in areas free of constraints.

Further information on current hydrogen regulatory framework and barriers can be found in section 11.4.

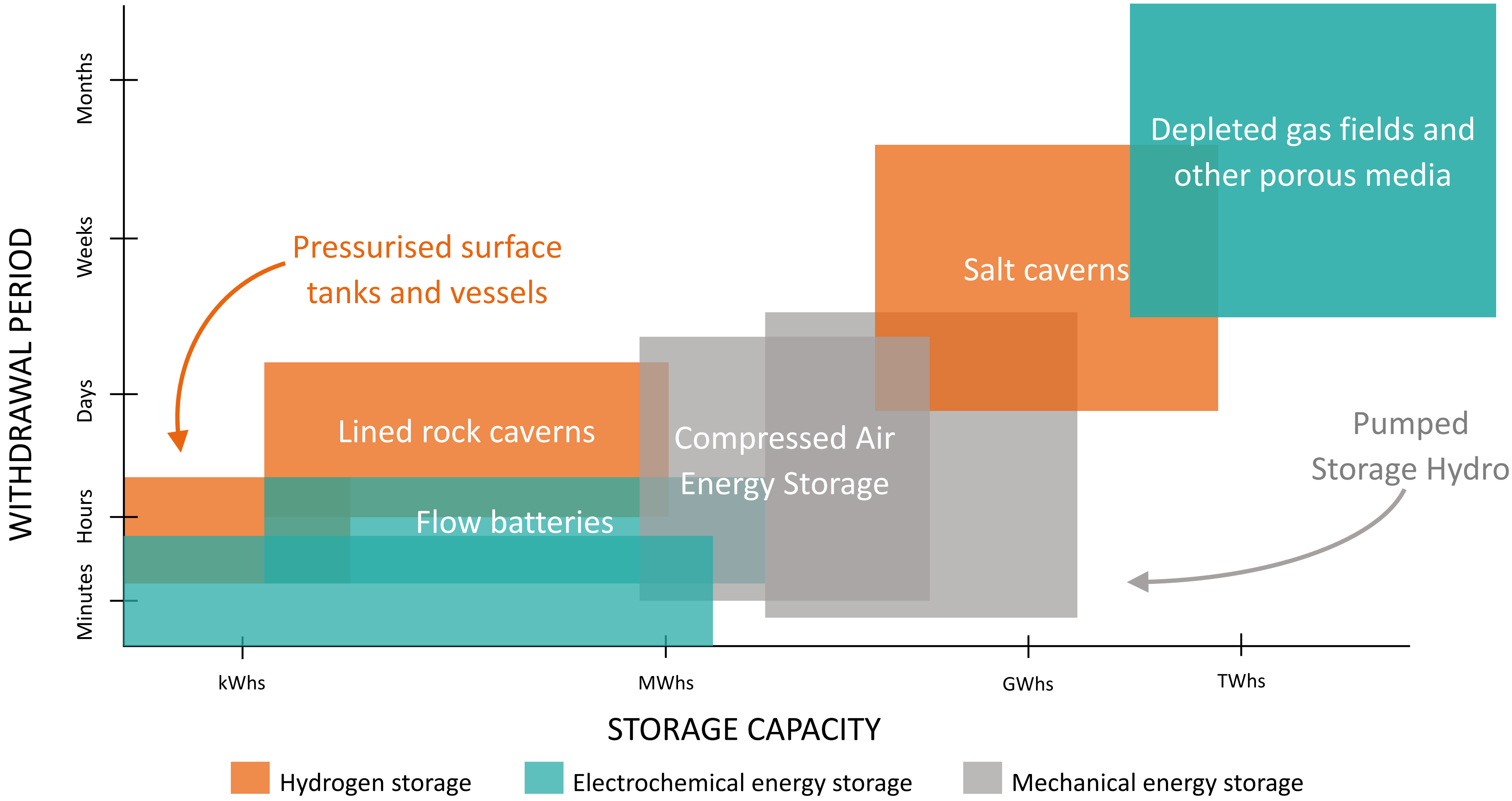

Figure 6 Energy storage technologies storage capacity vs withdrawal period

8 Conclusions and recommendations

Hydrogen storage will play an important role in providing flexibility in an energy system that has high penetration of intermittent renewable energy. It can supplement other forms of energy storage, such as pumped hydro and batteries, due to the greater scale and duration provided by hydrogen.

All of the hydrogen storage technologies covered in this report could support the flexibility of the UK energy system. Hydrogen storage technology suitability in Scotland is driven by geology, end use and how quickly it is required.

Small-scale hydrogen storage, such as compressed vessel storage and lined rock caverns, will be necessary for short-term storage and for early projects before the hydrogen pipeline infrastructure comes online. Adopters of small-scale hydrogen storage are likely to be producers and end users, such as smaller industrial sites, peaking plants, dispersed distilleries and hydrogen refuelling stations. However, small-scale storage is expensive per unit of energy stored so it is likely to play a smaller role than larger scale alternatives, especially in the long term.

Larger scale storage will be necessary to balance the intermittency of renewable energy. However, salt caverns are the only mature large-scale technology, and these are unlikely to be deployed in Scotland due to the unfavourable onshore geology. Other large-scale options such as depleted gas fields have potential in Scotland due to their capacity, existing infrastructure and widely available information on their structure. Less mature geological stores, such as aquifers, other porous media and larger lined rock caverns, also have potential in Scotland as they can be deployed almost anywhere. However, these are geologically less well-understood and need more research and pilots.

Hydrogen carriers and liquid hydrogen are most likely to be used for hydrogen export as they have high energy densities but low roundtrip efficiencies due to loss at conversion. Electricity that otherwise would have been curtailed could be used to produce liquid hydrogen or hydrogen carriers but their role to cut curtailment costs is likely to be very limited as they will not be used in power generation in Scotland and the rest of the UK.

While hydrogen storage will be needed for buffer, medium and long-term storage, hydrogen power generation is anticipated to add the most system value when it operates at low load factor during peak periods. This is due to lower capital cost and higher fuel costs compared to low-carbon alternatives such as gas CCS. The main benefit of hydrogen power plants when compared to other sources of electricity supply flexibility, like batteries, pumped storage hydro and gas power plants, is duration.

8.1 Recommendations for further work

1. **Feasibility studies and real subsurface trials** are needed in the short-term in porous media and lined rock cavern storage due to high suitability in Scotland, limited deployment data, and long lead times. With no access to underground salt layers, we

recommend identifying potential depleted gas fields that could support a centralised hydrogen storage system in the long term. We also recommend exploring lined rock caverns' potential in decarbonising dispersed sites and island communities in the short term.

2. Clear guidance and information on the production, storage and use of hydrogen could be provided to stakeholders, residents living near hydrogen sites and the general public, as **public buy-in** is key in meeting Scotland's net zero ambitions. This is not only critical to improve the perception of low-carbon technologies and net zero in general, but also to minimise residential opposition and accelerate developments. Therefore, we recommend the Scottish Government work closely with local councils and communities to:

    - make the public aware of the carbon footprint of hydrogen produced under government subsidies, the environmental impact of construction and operation of hydrogen storage facilities and how these facilities aid net zero

    - reassure the public that stringent safety requirements and systems are in place that manage the risk of hydrogen leakage and accidents on site.

3. Policymaking must ensure that regulation and other support mechanisms do not negatively distort the energy storage market framework. UK Government business models could be designed to incentivise investment and developed in tandem with those of other technologies to ensure timely, efficient and a cost-effective energy transition. **Strategic planning**, such as via cooperation between the UK and devolved governments and the emerging Future System Operator will be critical to cut renewables curtailment and maximise the system benefit of energy storage.

4. Welcoming the recent consultation on Offshore Hydrogen Regulation, we recommend that the Department for Energy Security and Net Zero, the Scottish Government, and Ofgem **review the existing onshore hydrogen regulatory framework** and identify regulatory barriers and opportunities for hydrogen storage projects.

5. As hydrogen regulation is fragmented and planning is devolved, the Scottish Government could provide developers and other stakeholders with **clear guidance** on planning, consenting and other regulatory requirements.

6. To support the early development of hydrogen storage projects, the UK Government should review its decision on **pre-2025 interim measures** for hydrogen storage projects. Short-term interim measures could include funding for feasibility studies so that developers are ready to take investment decisions by 2025 when the design of the Hydrogen Storage Business Model is complete.

7. Scottish Government's **continued engagement with key stakeholders**, including hydrogen storage and peaker developers, would help identify and track current market, technical and regulatory barriers.

9 Appendix A: Stakeholder interviews approach and list of stakeholders

We Interviewed stakeholders for one hour and followed a semi-structured format. Interviews began by presenting the scope of the project and gathering high level thoughts on the storage technologies considered as well as identifying any potential gaps in scope. Questions were structured around the seven evaluation criteria in the scope of the project. The topics focused on in interviews are shown with the list of stakeholders below.

List of commercial stakeholders:

- British Hydropower Association (pumped hydro storage)
- Carbon280 (metal hydride storage)
- Centrica (depleted gas hydrogen storage)
- SGN (above ground hydrogen storage, underground hydrogen storage, hydrogen derivatives)
- SSE (salt cavern storage, above ground hydrogen storage, hydrogen derivatives, electricity storage, hydrogen peaking plants)
- Statera (underground hydrogen storage)
- Confidential renewables and storage developer (batteries and hydrogen export)

List of academic stakeholders:

- Edinburgh Napier University – name withheld
- Heriot-Watt University – Gang Wang (porous media)
- Heriot-Watt University – John Andresen (all hydrogen storage)
- University of Edinburgh – Katriona Edlmann (underground hydrogen storage)
- University of Strathclyde – Graeme Hawker (energy system)

List of government stakeholders:

- UK Government - Department for Energy Security and Net Zero – Hydrogen Storage Business Model Team (hydrogen storage policy)

10 Appendix B: Electricity storage alternatives

Pumped storage hydroelectricity (PSH) is the most widespread large-scale electricity storage technology in the UK, accounting for 94% of UK's current electricity storage. At times of low demand or high renewable generation, water is pumped from a lower reservoir to an upper reservoir, which is released through a turbine when energy demand rises. Working on a similar basis, **Compressed Air Energy Storage** (CAES) facilities compress air into an underground cavern or reservoir at times of excess electricity generation. When power demand rises, air is released through a turbine, generating electricity.

Stationary batteries are also widely used for short-term energy storage in the UK. **Lithium-ion batteries** are a type of electro-chemical storage technology. During discharge, the battery provides an electric current as lithium ions flow from the anode to the cathode. **Vanadium redox flow batteries** (VRB) are also electro-chemical devices, working on different basis and using vanadium ions as charge carriers. As power is decoupled from capacity in the system, they can be scaled much more easily and cost-efficiently. VRB systems also charge and discharge without degradation.

10.1 Flexibility and whole system benefits

Pumped storage hydroelectricity (PSH), as noted above, accounts for 94% of UK's current electricity storage, meaning it supports the energy system with 2800 MW of installed capacity and 27.5 GWh electricity storage capacity [53]. Current pumped hydro storage facilities were originally constructed to balance nuclear and coal power plants, but today they mostly provide ancillary services for the grid [125]. In theory, pumped hydro facilities are well suited for energy arbitrage and peak shaving [70], but this role has been carried out gas peaking plants since the 1990s due to their cost advantage [125]. As PSH plants have shifted their production from peak shaving to more intra-day energy storage, these facilities sometimes go through 60 cycles a day. Although they have significant potential in Scotland [125] [126], their ability to balance the power grid may be affected by climate change as droughts become more frequent in the summers.

Underground **CAES** systems have not been deployed in the UK yet, but their relatively high efficiency and reliability would make them suitable for short, medium and long-term energy storage, such as ancillary services, black start and seasonal storage. However, their role in the energy system will depend highly on the specifics of the technology and the cost of available alternatives.

Lithium-ion batteries, with one to two hours of capacity provide significant whole-system benefit [18]. As they can respond to the Electricity System Operator's (ESO) orders within milliseconds (faster than gas plants), they are crucial for very short-term energy storage (see Figure 6), such as frequency response. As Li-ion batteries have significant competitive advantage in response time, only a small share of their revenue comes from the capacity market or the wholesale energy market [127]. **Flow batteries** store electricity as liquid, decoupling capacity from the power [128]. This means they are much easier to scale than lithium-ion batteries, allowing longer duration and higher capacity (see Figure 6). Vanadium redox batteries (VRB) are currently the most advanced flow battery technology. As they are highly suitable to support frequency control and provide emergency back-up, VRB systems are already being deployed at scale in the UK. Their potential for seasonal or periodic energy storage is currently investigated, but the current market framework, capacity limitations and cost-effective alternatives make these use cases unlikely. After 2030, both Li-ion and VRB systems are anticipated to experience growth in the four to six hours duration capacity levels [18].

Table 5 Flexibility capabilities of different electricity storage technologies

	Maintaining stability	Energy balancing	Load shifting	Daily cycles	Seasonal cycles
PSH	2	1	1	1	3
CAES	2	1	1	1	2
Li-Ion	1	1	1	3	4
VRB	1	1	1	3	4

Source: AFRY (2022) Benefits of long-duration electricity storage

1	No concern/ high suitability	2	Moderate suitability	3	Limited suitability	4	High level of concern/ No suitability

10.2 Development

Pumped storage hydro facilities have a relatively long lead time between five and eight years [53]. One of the greatest challenges of PSH is that it is geographically constrained. Previous research has identified more than a hundred suitable sites in the Scottish mountains and hills [126]. New ("greenfield") developments, however, can be subject to objections from the public or other PSH operators. Engaging with all stakeholders and addressing their concerns around landscape and visual impacts or traffic and transport could avoid delays in development.

Table 6 Operational and planned pumped storage hydroelectricity projects

Operator (or Applicant)	Site Name	Installed Capacity (MWelec)	Development Status	Country
Drax	Cruachan	440	Operational since 1966	Scotland
SSE Renewables	Foyers	300	Operational since 1974	Scotland
SSE Renewables	Coire Glas - Phase I	600	Revised in 2013	Scotland

Buccleuch Estates	Glenmuckloch Pumped Storage Hydro	400	Planning Permission Granted in 2016	Scotland
SSE Renewables	Coire Glas	1500	Planning Permission Granted in 2020	Scotland
Intelligent Land Investments	Red John Pumped Storage	450	Planning Permission Granted in 2021	Scotland
Drax Power Limited / Stantec UK	Cruachan Hydro Expansion	600	Planning Permission Granted in 2023	Scotland

Source: Renewable Energy Planning Database January 2023 [129]

As most **CAES** systems are underground, the development would not have as much visual impact as PSH. However, concerns around the traffic, noise and potential seismicity (see Section 10.6) could lead to public inquiries. As most underground CAES systems were built decades ago, there is no reliable data on development time. However, the UK's only operational (small-scale and aboveground) CAES took four months to construct [129]. As gas tightness of potential geological CAES sites need to be checked on a case-by-case basis, we expect their lead time to be significantly longer. There are also very few suitable sites for underground CAES systems in Scotland, but abandoned coal mines, rock mines and deep aquifers can be utilized [130].

Table 7 Operational and planned compressed air energy storage projects

Operator (or Applicant)	Site Name	Installed Capacity (MWelec)	Development Status	Country
Via East Midlands Limited	Cheesecake Energy Air Energy Storage	NA	Operational since 2021	England
EDF Trading Gas Storage Limited	School Lane, Warmingham - Compressed Air Energy Storage	5	Planning Permission Granted in 2022	England

Source: Renewable Energy Planning Database January 2023 [129]

The construction time of a **stationary battery** is normally less than two years, with some projects going online after six months [129]. The consenting phase is simpler for VRB systems as they do not require special fuel handling requirements and do not pose significant fire risk. However, if the installed capacity of any electricity storage project exceeds 50 MW or it is co-located with high-capacity generators, they must be consented by Scottish ministers [131] [132]. This can potentially lengthen the development process as local planning authorities are likely to grant planning permits more rapidly [129]. Since 2020, electricity storage projects that are not pumped hydro, and are above 50 MW, have been streamlined in England and Wales and so do not go through the Nationally Significant Infrastructure Projects (NSIP) regime. NSIPs are large scale projects in England and Wales that are consented by the Planning Inspectorate instead of local planning authorities. In Scotland, planning is a devolved process and currently around the third of all battery developments are still consented by Scottish Ministers [129]. There are currently 85 battery projects and one PSH project in Scotland waiting for their planning applications to be approved [129]. Other factors, such as time to be connected to the transmission network, also affect lead times (see Table 9).

10.3 Technical feasibility

PSH is one of the most mature electricity storage technologies, at TRL 9. Its high round-trip efficiency of 65-80% [133], low self-discharge rate [134], long lifetime and capability to store energy for long periods of time made it a very attractive public investment from the 1960s until the early 80s [135] [136]. There are only a few factors limiting the technical feasibility of PSH, such as geographical constraints [137] and limited expertise in construction.

CAES is a tried and tested technology, but there are only few commercial plants in operation (TRL 7). CAES systems have acceptable round-trip efficiency (50-89%) and long lifetime but generally low energy density. The low energy density can be somewhat mitigated by higher pressures, but this will potentially decrease operational efficiency and lead to geomechanical risks [138] [139]. They require less space compared to PSH plants, can store energy for longer durations and are easily scalable in terms of both capacity and power output [130].

Li-ion batteries are a highly mature technology (TRL 10), and the only electricity storage technology that has significantly increased capacity in the past years. This is because it is highly efficient (85-95%), has moderate energy density and can respond to Electricity System Operator's orders within milliseconds. However, it has serious technical limitations such as capacity and self-discharge, making Li-ion batteries unsuitable for longer durations. To mitigate technical challenges and ensure that the battery is not overheating, complex battery management systems are also needed.

VRB systems have lower TRL (7), but they are expected to have an important role due to some of their very attractive properties. The greatest advantage of VRB is that it is very easily scalable as capacity is decoupled from power. This means that the capacity of a grid-scale battery can be increased more efficiently. VRB also have acceptable efficiency (60-70%), large cycle life and are generally easy to recycle [137]. However, they also have relatively high self-discharge rate and low energy density. It is estimated that VRB systems have double the site size compared to Li-ion batteries with the same capacity [137]. Moreover, high-rate operations can cause complex thermal issues and side reactions, making battery management systems crucial for safe operation [140].

10.4 Scottish supply chain

There is an existing and stable **PSH** supply chain as there are already two large-scale facilities operating in Scotland. In this sense, there is low level of concern with regards to PSH supply chain. However, our stakeholder engagement found that the supply chain is not entirely ready for new developments, with the last plant being completed in 1974. Although there is considerable experience in operating and maintaining PSH systems, developers currently face supply chain bottlenecks in the construction phase. Despite these challenges, it is important to highlight Scotland's strengths and opportunities in component manufacturing (e.g. gates, valves, generators, penstocks, transformers and turbines) [141]. As Scotland and the wider UK has strong expertise in valve, generator and turbine manufacturing, PSH has high potential to support Scottish and local supply chains [142] [143] [144].

In contrast to PSH, there is much less experience with the construction of **CAES** systems. The UK has relevant expertise in underground gas storage that can be leveraged. However, developers would have to rely on international engineering consultancies to fully understand the technicalities of CAES construction. Scotland has considerable opportunity in high-capacity compressor manufacturing. Expertise in smaller-scale CAES systems is moderate, as there are two companies currently developing or operating such systems in Nottinghamshire and Cheshire [129].

The **lithium-ion and vanadium battery** supply chains are highly complex, and more research is needed to identify gaps and opportunities in this area. Our high-level research found that the UK has little expertise at most stages of the Li-ion supply chain. Mining, material processing and manufacture of most cell components takes place outside of the UK [145]. However, there are several battery pack assembly sites and gigafactories in the pipeline, mainly focusing on EV battery manufacturing. The new owner of Britishvolt battery manufacturing facility in Northumberland, however, are pivoting to grid-scale, stationary energy storage [146]. In terms of VRB manufacturing, Scotland has considerable strengths, with Invinity Energy Systems' vanadium redox flow battery factory in Bathgate being one of the world leaders in this area [147]. There are also capabilities in designing, installing, testing, operating batteries and integrating them with battery management and revenue modelling systems [145].

10.5 Economics

In 2010, a study by environmental-energy consultancy AEA Technology (now Ricardo) found that constraining generation or investment in interconnectors would be more economical compared to electricity storage projects [148]. Although this is not applicable to short-term storage anymore due to significant battery cost-down, this finding continues to be relevant for medium and long-term storage. In addition to more lucrative alternative investments, there are a number of financial barriers, such as upfront capital cost, the cost of capital, long lead times and lack of revenue certainty [149] (further entry barriers detailed in Table 9 in section 10.7).

Despite the high capital cost of £500 million [150], **PSH** projects can store energy at a very low cost. Multiple papers have confirmed that for energy storage of more than four hours, PSH is the cheapest existing option available today [125] [70]. However, cost is not the only economic factor that has to be considered. As previously noted, pumped hydro was highly suitable for energy arbitrage before gas peaking plants came online in the 1990s [125]. This means that PSH facilities, in the current market and regulatory framework, are economically incentivised to support ancillary services and run multiple cycles a day (see Table 8). When they were built, they operated on daily cycles. Now, the number of daily cycles can reach 60

[151]. Although PSH can store energy for multiple days at a very low cost, our research found that operators may not have the economic incentive in the current market and regulatory framework to shift their operation from support ancillary services to intra-day storage.

Table 8 Potential revenue streams for electricity storage projects

Revenue stream	Value	Route to Market
Frequency Response	High	Ancillary Services
Frequency Control by Demand Management	Medium/High	Ancillary Services
Fast Reserve	Medium/High	Balancing service
Capacity Market	Medium	Capacity Auction
Transmission cost avoidance	Medium/High	Market mechanism/cost avoidance
Distribution cost avoidance	Medium/High	Market mechanism/cost avoidance
Generator grid curtailment	Low/Medium	Market and subsidy
Price arbitrage & peak shaving	Low	Market

Source: Regen SW [151]

CAES systems operate with lower costs, making them more suitable for longer duration storage. Although their CAPEX is lower than PSH systems, the upfront capital cost is still a major financial barrier. This is illustrated by the fact that the only currently operational (small-scale) CAES system in the UK can only be developed with funding under the Longer Duration Energy Storage competition (see Table 7).

Electrochemical storage is the most expensive storage technology. Due to their high cost, they are mainly used for very short-term storage to gain the highest revenue. In the electricity market, the faster a generator responds to the ESO's order, the greater is the arbitrage opportunity (see

Table 8). This is reflected in their revenue profile as more than 80% comes from frequency response with 47% specifically from high frequency dynamic containment [127], [152]. Consequently, only around 10% of their revenue comes from the capacity market and the wholesale energy market [152]. This is, however, expected to change as more batteries come online [153]. Vanadium redox flow batteries are not yet deployed on such a large scale as lithium-ion batteries, but we can already see the future cost disparity between the two. Although the CAPEX of VRB systems is currently higher than Li-ion batteries [82], significant cost reductions are expected due to the simplicity and the recyclability of the system. VRB systems also have a higher number of theoretical cycles at 15,000-20,000 cycles compared to lithium ion at 3,000-5,000 cycles.

10.6 Sustainability and safety

PSH systems have generally little environmental impact if they are brownfield sites and have a closed loop. A closed loop pumped hydro system does not involve a connection to any body of water. If any of the reservoirs are part of a river or a lake, PSH facilities can negatively affect water quality and biodiversity in the long term [154], [137]. An Environmental Impact Assessment (EIAs) is needed for each development to assess its effect on biodiversity and terrestrial and aquatic ecology. Recent PSH developments in Scotland, for example, faced objection from local fisheries who were concerned about salmon migration [155]. With appropriate maintenance, PSH systems have a long lifetime and can support the electricity system for up to 100 hundred years however, making EIAs even more important.

Underground **CAES** systems generally have a very low environmental impact. It mainly affects its surrounding environment through land use and noise. Similarly, to most geological energy storage technologies, injecting and withdrawing air from the facility has to be done with care. Frequent cycling may affect the geological integrity and induce seismicity [139]. Repurposing depleted gas fields for CAES can also increase fire and explosion risks due to residual hydrocarbons [156]. The carbon footprint of the CAES system also depends on the type of system deployed. Diabatic CAES, for example, still requires fossil fuel consumption for operation. This is because the released air needs to be heated before it is released through the turbine. Adiabatic CAES, on the other hand, can recover waste heat from the compression process, eliminating the need for any combustion [157].

Lithium-ion batteries have a crucial role in enabling higher renewable generation. However, there are concerns at most stages of the life cycle. Lithium and nickel mining is associated with large environmental footprint and human rights concerns. It takes more than two million litres of water to mine one tonne of lithium [158]. Lithium-ion batteries are highly flammable and toxic. They typically last for 3,000 – 5,000 cycles (around 10 years), with the option to operate longer with reduced capacity (approximately 80% of original capacity). At the end of life, it is highly challenging to take lithium batteries apart. Historically there has very little economic incentive to recycle them, with only approximately 5% of EV batteries being recycled today [159]. However, recent funding in battery recycling is likely to increase this proportion.

When it comes to sustainability, **Vanadium Redox Flow Battery** (VRB) systems have a clear competitive advantage over lithium-ion. They have a better environmental impact as their lifetime can exceed 20 years after which most components can be 100% recycled. Most of the system, especially the electrodes, do not degrade with cycling [160] and they produce very little noise [137]. Vanadium is only toxic at high concentration and the battery itself is not flammable, in contrast to lithium-ion batteries. Although they contain some toxic chemicals, such as sulphuric acid, they lack potentially toxic metals, such as lead, cadmium and zinc, significantly reducing the battery’s environmental impact throughout the lifecycle [161].

10.7 Policy and regulatory framework

The Scottish and the UK Government are both supporting innovative projects through various schemes including the Longer Duration Energy Storage Demonstration Competition (LODES), the Faraday Battery Challenge and the Scottish Enterprise Advancing Manufacturing Challenge Fund [48] [162] [163].

The Scottish Government has long been supportive of PSH projects. In the Fourth National Planning Framework, pumped hydro was identified as a nationally important electricity storage technology. With regards to long-duration electricity storage projects generally, the UK Government has identified several market and regulatory barriers. To address these, DESNZ have committed to developing appropriate policy to enable investment by 2024 [149].

Further market and regulatory barriers and how they are expected to be addressed in upcoming market reforms (see Table 9).

Table 9 Market and regulatory bottlenecks for electricity storage projects

	Description	Expected steps	Impact	Source
Transmission Network Use of System (TNUoS)	The network charging system is a major disincentive for developers to deploy electricity storage projects in the whole of Great Britain. Due to higher-than-average transmission tariffs, this is particularly true in the north of Scotland.	Ofgem launched a TNUoS Taskforce and is currently working on addressing this bottleneck.	High	Link Link
Capacity Market	Projects with duration over five and half hours and construction period of more than four years are not eligible for capacity market auctions.	Capacity Market reform is expected to address these bottlenecks.	High	Link
Unlevel playing field	Interconnectors have a contract of 25-year term and can distort the market for flexibility, with LDES having no support mechanism.	Cap and Floor business models for LDES projects to designed by 2024.	High	Link
Balancing Services	National Grid ancillary balancing services contracts are not long enough to provide revenue certainty to developers.	No change is expected in the near future.	Medium	Link
Balancing market	The required construction time for balancing market contracts (six years) is too short for large-scale projects.	No change is expected in the near future.	Medium	Link
Planning and Consenting	LDES projects above 50 MW need a consent under Section 36 of the Electricity Act 1989 for the construction, or extension, and operation of the generating station. Many developers find the planning and consenting regime lengthy and complex, with some experiencing considerable delays.	Fast track process is expected (Levelling Up and Regeneration Bill)	Medium	Link
Grid connection	With more than 600 projects in the queue, it can take more than a decade to get connected to the transmission network.	National Grid is currently working on shortening the waiting list.	Low	Link Link

11 Appendix C: Technical tables

Table 10 Technical details for storage options

TECHNOLOGY		ROUND-TRIP EFFICIENCY (%)	RESPONSE	LIFETIME (yrs)	TECHNOLOGY READINESS [75] [34]	STORAGE TEMPERATURE (°C)	STORAGE PRESSURE (bar)	CHARGE AND DISCHARGE RATES	TOXICITY	FLAMMABILITY
Above ground	Vessel	37	Minutes	10	9	Ambient	350-700	High	Low Concern	Potential Concern
	Linepack	37	Instant	40	9 new built, 7 repurposed	Ambient	50-80	High	Low Concern	Potential Concern
Under-ground	Salt caverns	37	~ 1 hour	30	9	20-60°C [75]	360 [17]	High	Low Concern	Potential Concern
	Depleted gas fields		12-24 hours	30	3-4	30-150°C [75]	250 [17]	High	Low Concern	Potential Concern
	Saline aquifers and porous media			30	2-3 [75]	30-150 °C	250	High	Low Concern	Potential Concern
	Lined rock cavern		Minutes	30-35 [164]	5 [75]	0-43°C [165]	100-250 [32]	High	Low Concern	Potential Concern
Hydrogen conditioning	Liquid hydrogen	9-22 [166]	~ 1 hour		9 [167]	-252.8	Ambient	Medium	Low Concern	Potential Concern
	Ammonia	22	>4 hours		9 [167]	-33	Ambient	Medium	Potential Concern	Potential Concern
	LOHC	~18 [168]	>4 hours		7 [167]	Ambient	Ambient	High	Potential Concern	Potential Concern
	Magnesium hydrate	N/A	N/A		4	Ambient	Ambient -40	Low/ medium	Low Concern	Low Concern
Electricity storage	Pumped hydro	65-87	<60 seconds	up to100	9	Ambient		High	Low Concern	Low Concern
	Compressed air	50-89	<60 seconds	25	7 [169]	Ambient	up to 100 [170]	High	Low Concern	Low Concern
	Lithium-ion battery	85-95 [171]	0.15-1 seconds	5-15	10	Ambient		High	Potential Concern	Potential Concern
	Flow battery	70-80	0.5-1	15-20	7	Ambient		High	Low Concern	Low Concern

11.1 2030 Capacity requirements

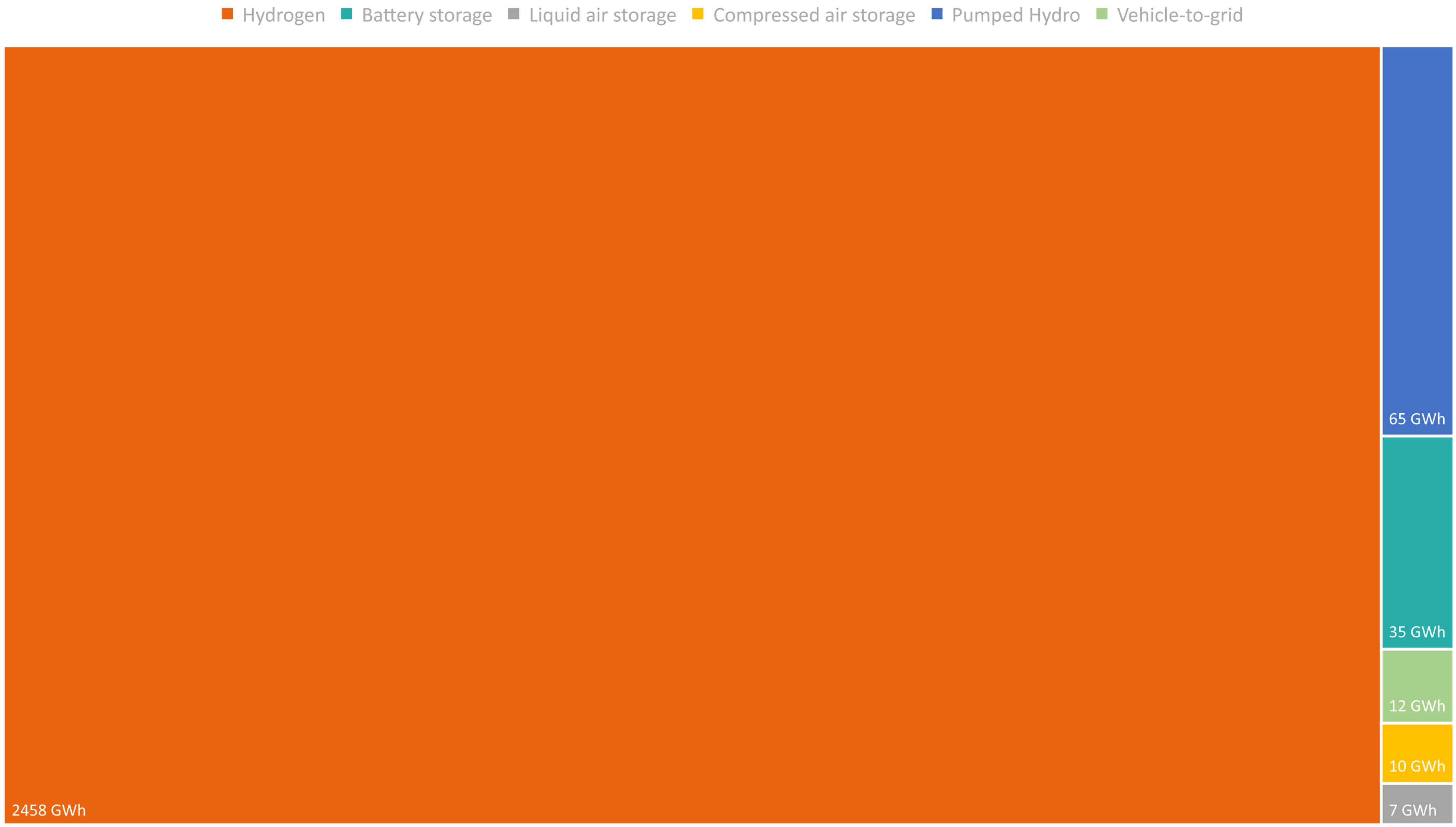

Figure 7 2030 Energy storage requirements by technology under Leading the Way scenario (National Grid FES 2022)

11.2 Hydrogen storage technologies

11.2.1 Development

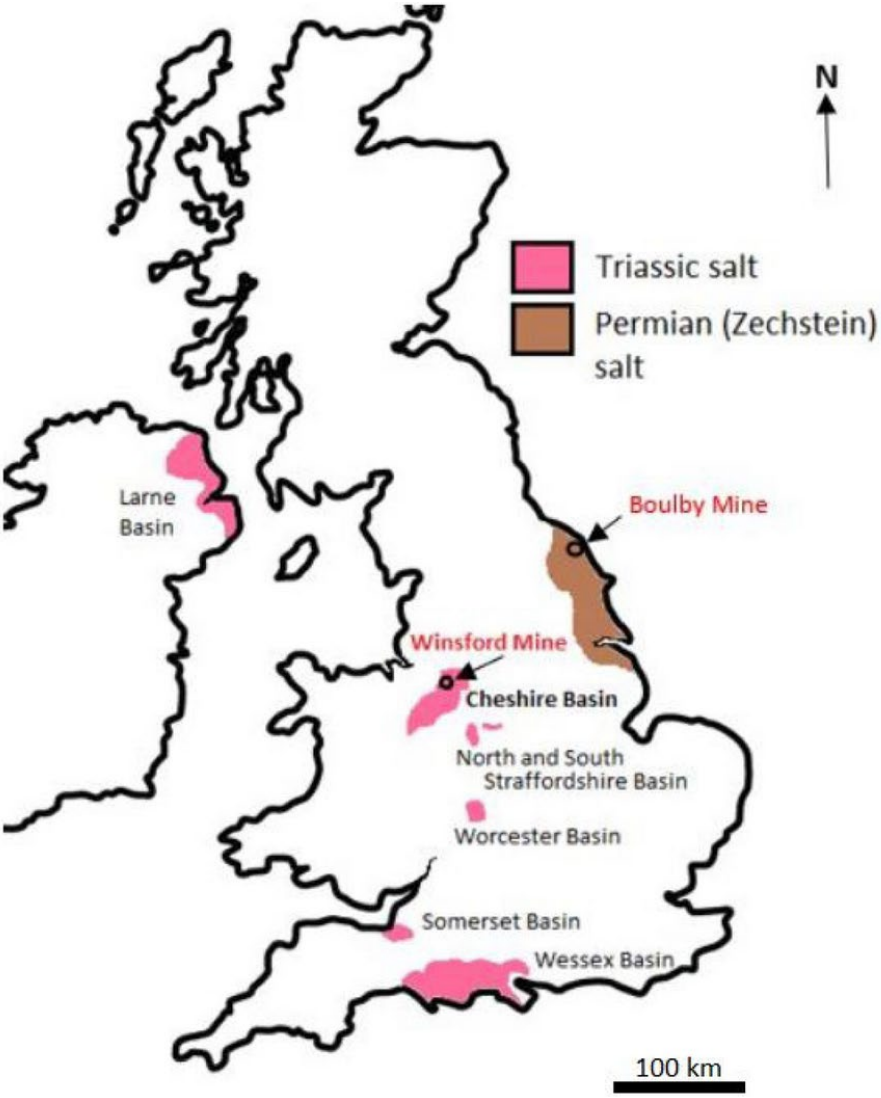

Figure 8 Triassic and Permian salt fields in the UK

Source: British Geological Survey [172]

Figure 9 Proposed underground hydrogen storage projects in the UK and their potential capacities

Source: BEIS (2022) [173]

11.2.2 Technical feasibility

Table 11 Technical table of underground hydrogen storage technologies

	Salt caverns	Depleted gas fields	Other porous media	Lined rock caverns
Cushion gas	Cushion gas 25-35% [32]	Cushion gas 33-66%, highly dependent local conditions [75]	Cushion gas: aquifer 50-70% [32]	10-20%
Efficiency	Roundtrip efficiency disadvantages over batteries could be overcome in 12 hours [174]			
Discharge rate [175]	High	Average	Low	High, with very fast cycling
TRL [75]	5-9, depending on the cycle profile	3-4	2-3	5
Geography	Limited, no salt strata in Scotland	Limited but more widespread than salt caverns. Scotland has direct access to multiple depleted gas fields	Widespread	No geographic constraint
Capacity [175]	Medium, depending on cavern size	High	Medium	Low to Medium
Experience with the technology	Operational salt caverns in Teesside, planned salt caverns in Cheshire, Humber and Dorset	Underground Sun Storage in Austria, Rough is planned to be repurposed by 2030	No experience with 100% H_2 storage. Some data is available due to town gas storage	Mature technology for natural gas storage. One 100% H_2 pilot project in Sweden.
Strengths	Highest technical maturity	Highest capacity Data availability Existing infrastructure	Geographically widespread High capacity	No geographic constraints Ability to store liquified as well as compressed

<table>
<tr><th></th><th>Salt caverns</th><th>Depleted gas fields</th><th>Other porous media</th><th>Lined rock caverns</th></tr>
<tr><td></td><td></td><td></td><td></td><td>hydrogen [32]</td></tr>
<tr><td rowspan="8">Risks and weaknesses</td><td rowspan="3">Hydrogen salt caverns with high cycle rates are less well understood</td><td colspan="2">Hydrogen contamination</td><td rowspan="4">Small-scale, low capacity</td></tr>
<tr><td colspan="2">Loss of hydrogen due to microbial processes</td></tr>
<tr><td rowspan="2">Potential changes in porosity and permeability [176]</td><td>Potential changes in porosity and permeability</td></tr>
<tr><td rowspan="3">Salt creep – loss of available storage volume</td><td>As water invades the reservoir, the working gas capacity may decrease</td></tr>
<tr><td>Diffusion through caprock. 2% loss have been reported throughout lifecycle [176]. Diffusion is estimated to be more intense in the short-term when the formation water in the caprock is not yet saturated with hydrogen</td><td>Aquifers don’t have an impermeable caprock as depleted gas fields. They may not be tight on all sides [50]</td><td rowspan="2">No commercial deployment.</td></tr>
<tr><td colspan="2">Fatigue of reservoir rock and possible fracture development</td></tr>
<tr><td colspan="3">Risk of leakage due to lower viscosity and density of hydrogen</td><td>Leakage risk currently unknown</td></tr>
<tr><td colspan="4">Mixing and migration of hydrogen into cushion gas</td></tr>
</table>

	Salt caverns	Depleted gas fields	Other porous media	Lined rock caverns
Mitigation	Appropriate injection and withdrawal speed Piloting fast-cycle hydrogen salt caverns	Appropriate site selection Appropriate injection and withdrawal speed Launching 100% hydrogen depleted gas field pilot in Scotland	Appropriate site selection Appropriate injection and withdrawal speed Launching 100% hydrogen pilot in Scotland	100% hydrogen lined rock cavern pilot in Scotland
Note: Although there are several technical, microbial and geochemical challenges, our stakeholder engagement suggested that all of them can be mitigated through careful site selection and cycling.				

11.2.3 Supply chain

Table 12 Strengths, opportunities and gaps in the Scottish UHS supply chain

	Strengths and opportunities	Gaps
All technologies	Existing experience in small-scale compressor manufacturing [66] Design and engineering of storage infrastructure Civil and structural material (including buildings) [66] Academic research and engineering consultancy Construction and installation (labour)	High pressure compressors Training for new technical and safety standards [177] Equipment design for safety cases [177]
Salt caverns	Civil and structural material (buildings) market opportunity [66] Capabilities in operating hydrogen and natural gas salt caverns in England [66]	No experience in salt caverns but expertise in gas storage can be leveraged Equipment design for salt cavern storage Limited experience in brine developing brine infrastructure for disposal Limited experience with repurposing exiting salt caverns

Depleted gas fields	Expertise and value chain of existing hydrocarbon industry Strength in R&D and education (e.g., HyStorPor) Engineering services	No specific gaps related to depleted gas fields
Other porous media	None have been identified	Limited experience in gas storage in other porous media
Lined rock cavern	Existing high-pressure vessel capabilities	Limited experience in line rock cavern
PROGRESS TO DATE		
To address gaps in supply chain and skills, a number of initiatives and support schemes have been launched, such as Fit for Hydrogen programme, National Skills Accelerator, UK Energy Supply Chain Taskforce (UKESC), Hydrogen storage and distribution supply chain collaborative R&D Competition [178]. The Scottish Government is also launching/has launched the Green Jobs Fund, Young Person's Guarantee, Hydrogen Innovation Scheme (HIS), The Scottish Hydrogen Innovation Network (SHINE), Hydrogen Accelerator. Scottish Enterprise is also working on identifying supply chain opportunities and gaps. Although supply chain capabilities have been noted in both the 2020 Hydrogen Policy Statement and in the 2022 Hydrogen Action Plan, the hydrogen storage supply chain needs in Scotland have not been explored in detail to date.		

11.2.4 Economics

Table 13 Economics of underground hydrogen storage technologies

	SALT CAVERNS	DEPLETED GAS FIELDS	OTHER POROUS MEDIA	LINED ROCK CAVERN
Upfront cost	High	High	High	Moderate depending on size
CAPEX (per kW)	Low Estimated to be £100-150 per kW [50]	Low N/A	Low N/A	High $44-160 per kg [69]
OPEX (per kW)	Moderate Approximately £3.8-6.8 per kW/year [50]	Low N/A	Low N/A	Moderate $7-26 per kg [69]

Largest expense	Formation of the cavern, disposal of the brine, cushion gas, compression [17]	Well, infrastructure, cushion gas, compression [17]	Exploration and determination of geology, well infrastructure, cushion gas, compression [17]	Blasting of the cavern Steel lining Cushion gas Compression [17]
Cushion gas need	Moderate	High	High	Low/moderate

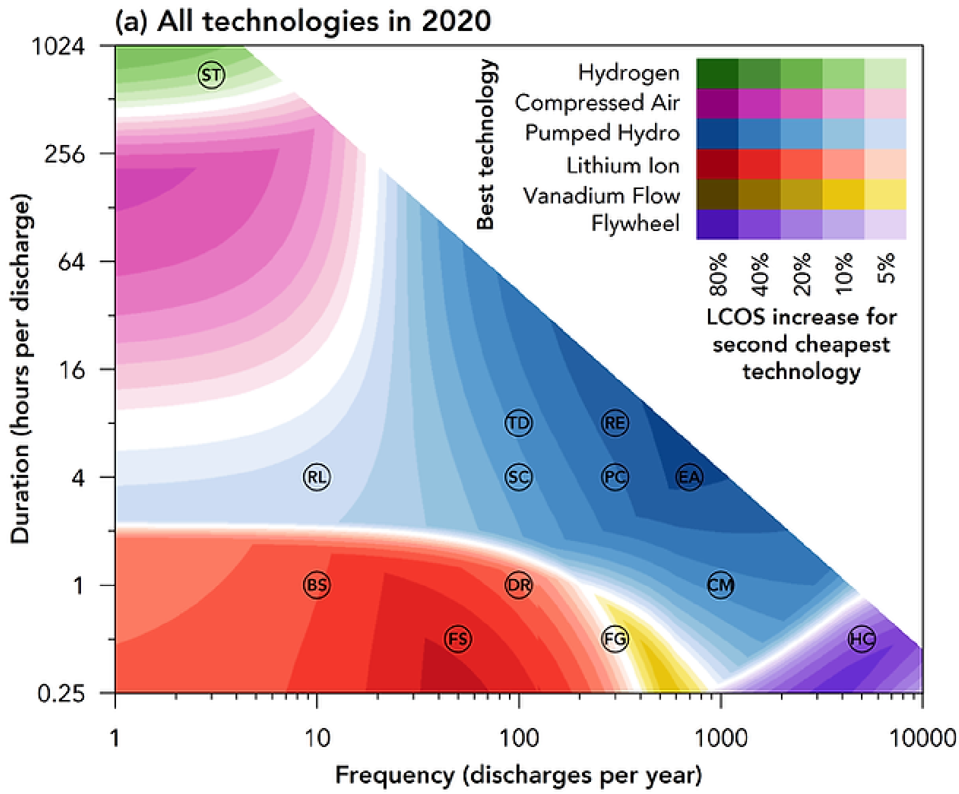

Figure 10 Storage technologies with the lowest levelized cost of energy storage in 2020. Source: Storage Lab [70]

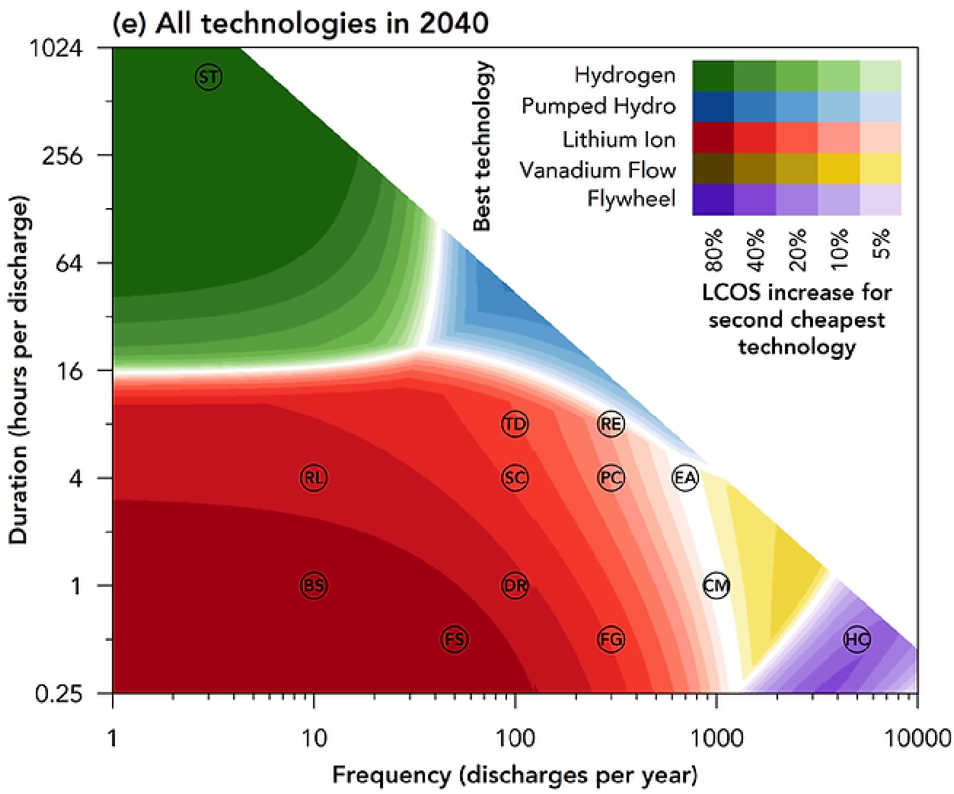

Figure 11 Storage technologies with the lowest levelized cost of energy storage in 2020. Source: Storage Lab [70]

11.2.5 Policy support

Compressed hydrogen storage projects funded under UK and Scottish support schemes

Both the UK and Scottish Governments are supporting UHS technologies through various funding streams including but not limited to the BEIS Energy Innovation Portfolio, the Longer Duration Energy Storage Demonstration Competition (LODES), the HPBM, the UK Government's Net Zero Hydrogen Fund, the Scottish Government's Hydrogen Innovation scheme and Innovate UK.

The UK Government also supported the HySecure project, which demonstrated the deployment of grid-scale storage of hydrogen in a salt cavern [179].

In May 2023, the following hydrogen storage projects received funding under the Scottish Government's Hydrogen Innovation Scheme:

- H2GEN
- Hybrid Hydrogen Storage and Distribution – compressed vessel
- Discontinuum Modelling for a Lined Rock Hydrogen Storage Shaft – lined rock cavern/shaft
- H2Shore - Hydrogen coastal storage and distribution
- StorageUpscale – underground storage
- Comprehensive one stop hydrogen storage testing (Hy-One)
- Glasgow Hydrogen Airport Innovation Hub

- Green Hydrogen Integration at Sullom Voe
- Decoupled Electrolyser, Storage, and Offshore Wind (DESOW)

11.3 Liquid hydrogen and carriers

11.3.1 Technical feasibility

Table 14 Technical table of liquid hydrogen and carriers

	Hydrogen (700 bar)	Liquid ammonia	Liquid hydrogen	MCH	MH_2
Volume containing 100 kg of hydrogen (m^3)	~2.38	0.83-0.93	~1.41	2.11-2.12	0.92-1.16
Total weight containing 100 kg of hydrogen (kg)	100	~566.57	~100	1,623.38	1,666.67-1,315.79
Volumetric hydrogen density (kg per m3)	42	107.7-120	~70.8	47.1-47.4	86-109
Gravimetric hydrogen density (MJ per kg)	120-142	21.18- 22.5	120-142	~7.35	9-10.8
Purification requirement after reconversion	Not applicable	Yes	No	Yes	No

Source: The Oxford Institute for Energy Studies [17] and stakeholder engagement

11.3.2 Economics

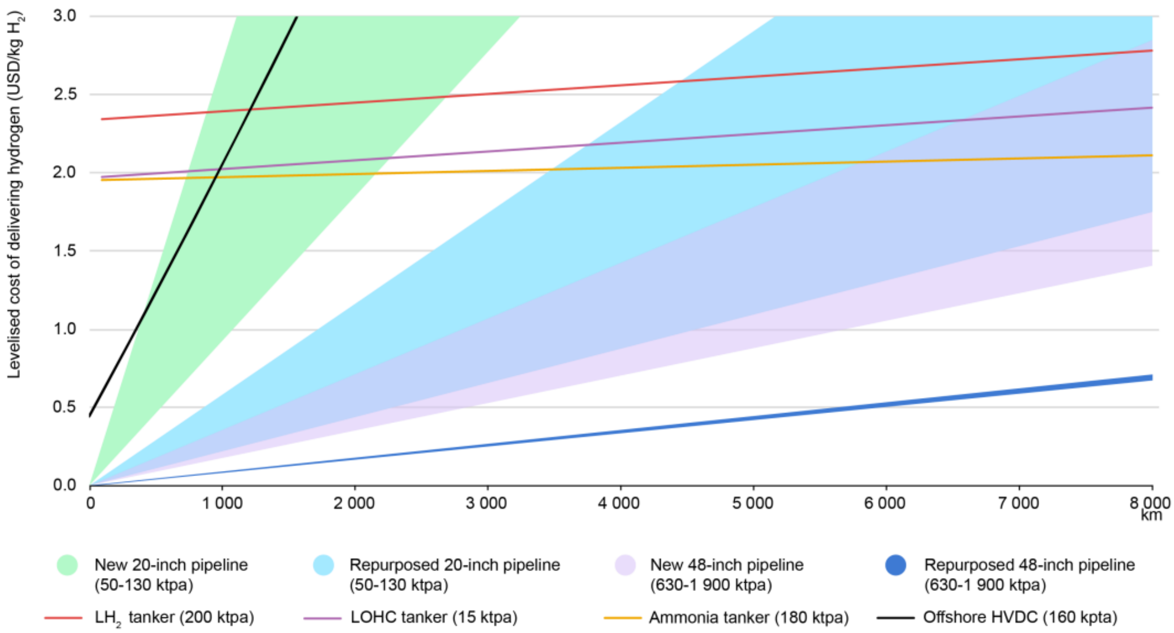

Figure 12 Levelised cost of transporting hydrogen by pipeline, liquid hydrogen and hydrogen carriers
Source: IEA (2022) Global Hydrogen Review 2022 [32]

11.3.3 Sustainability

Table 15 Sustainability level of concern for liquid hydrogen and carriers

	NH3	Liquified H_2	MTH	MgH_2
Natural gas use	Yes	Yes	No	No
Toxicity	4	1	4	1
Flammability	3	4	4	1 if suspended in oil 3 otherwise

1	No concern	2	Low level concern	3	Medium level concern	4	High level of concern

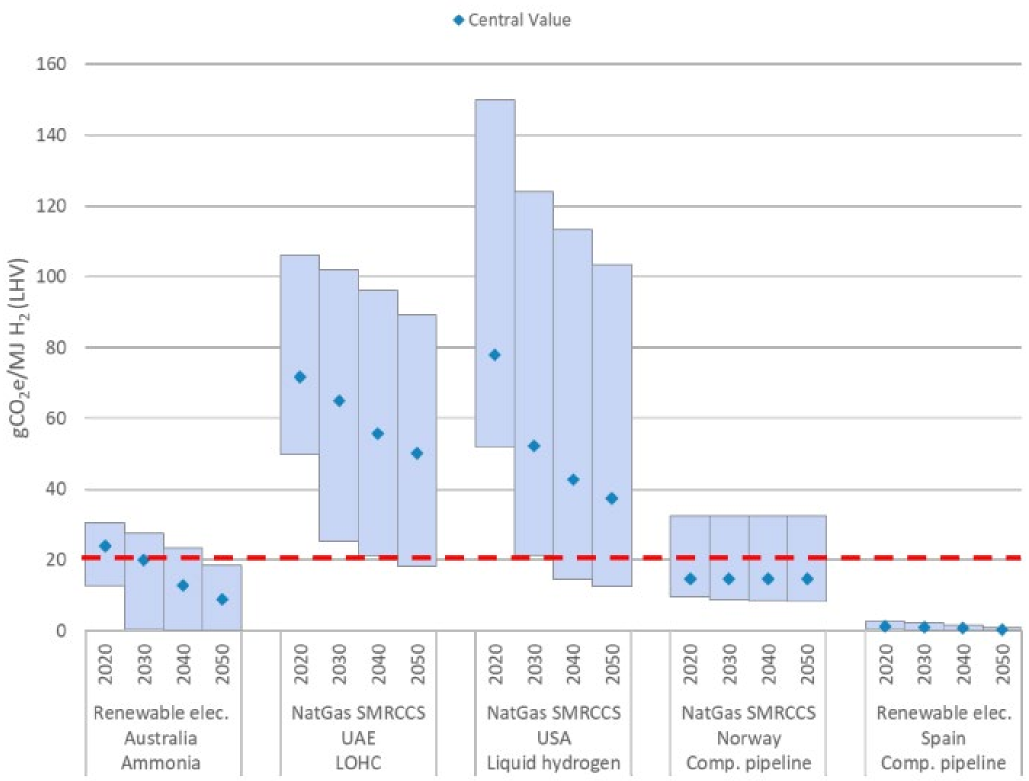

Figure 13 Overseas production and import emissions (scenario ranges, 2020 to 2050, red dotted line as UK production threshold) Source: E4Tech [103]

11.3.4 Policy support

Liquid hydrogen and hydrogen carrier projects funded under UK and Scottish support schemes

Net Zero Technology Centre and ERM have recently launched their Liquid Organic Hydrogen Carrier for Hydrogen Transport project, with the support of the Scottish and the UK Government, to demonstrate the feasibility of LOHC transportation from Scotland to the Port of Rotterdam [180]. The consortium HI-FED also received £3.8 million funding from the UK Government to build and showcase its innovative autonomous vessel and bunkering infrastructure technologies for liquid hydrogen. Solid state technologies developed by Carbon280, Gutteridge, Haskins & Davey Ltd and H2GO Power also received funding under LODES and Low Carbon Hydrogen Supply 2 Competition. However, our stakeholder engagement suggested that more funding is needed for feasibility studies and trials.

11.4 Hydrogen regulation

11.4.1 Gas Act 1986 and fragmented hydrogen regulation

With no comprehensive hydrogen-specific regulation in place, onshore hydrogen is regulated under the Gas Act 1986 and Planning Act 2008. As hydrogen is defined as "gas" under the Gas Act, most transportation, storage, and supply regulatory requirements of natural gas applies to hydrogen as well. Hydrogen is currently not defined as gas under the Energy Act 2008, meaning that offshore hydrogen injection and storage is not yet covered by any regulation. The UK Government, however, confirmed in the Offshore Hydrogen Regulation Consultation that this definition would be changed to align with the UK's net zero ambitions [181]. Our stakeholder engagement confirmed that more concise and hydrogen-specific regulation is needed in the UK which reflects its critical role in a net zero energy system.

11.4.2 COMAH and Hazardous Content consent

Control of Major Accident Hazard (COMAH) applies to hydrogen and most of its derivatives, such as ammonia, methylcyclohexane and toluene. Magnesium hydride, however, is not considered a dangerous substance under COMAH [182]. In Scotland, COMAH regulations are enforced by the COMAH Competent Authority.

Sites handling hydrogen and its derivatives must meet either Upper Tier or Lower Tier requirements, depending on the volume of substances produced, stored or used. If a site stores hydrogen carriers, such as ammonia, methylcyclohexane or toluene or has any intermediate storage, it will likely be at least Lower Tier. If the on-site storage capacity exceeds 7 days, the hydrogen facility is likely to be Upper Tier [183]. During our research, one stakeholder suggested the review of COMAH regulation for hydrogen as the low thresholds may slow down hydrogen developments.

Their requirements for a Hazardous Substance Consent (HSC) are similar to the ones set in COMAH. However, some HSC requirements are more stringent, with additional requirements for hydrogen [183].

Table 16 COMAH Lower Tier (LT) and Upper Tier (UT) Thresholds

Substance	COMAH Schedule 1 Category	LT Threshold (te)	UT Threshold (te)
Hydrogen	15	5	50
Ammonia	35	50	200
Toluene	P5c	5000	50000
Methylcyclohexane	P5c / E1	100 (E), 5000 (P)	200 50000

11.4.3 Policy and regulatory barriers

- **Carbon dioxide as cushion gas**
  Our stakeholder engagement found that using carbon dioxide as cushion gas is not permitted under The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010, despite having the potential to significantly reduce the capital cost of UHS developments. That is, when hydrogen is withdrawn from an underground reservoir, some carbon dioxide may also be accidentally withdrawn due to contamination. Withdrawal of CO2 from underground storage facilities, however, is not yet permitted. Amending these regulations, will accelerate the deployment of hydrogen storage in underground porous media as alternative cushion gases, such as hydrogen itself, are more expensive and less abundant so will slow deployment.
- **Hydrogen production business model design**
  The design of the Hydrogen Production Business Model (HPBM) can also pose certain barriers to hydrogen storage project. For example, producers who are supported under HPBM cannot currently sell their hydrogen to intermediaries.
- **Interim measure**
  With no interim measure before the 2025 design of the hydrogen storage business model, hydrogen storage developers face significant market barriers, such as revenue uncertainty. Our stakeholder engagement confirmed that developers need a support mechanism prior to 2025 to make final investment decision.
- **ADR regulation**
  Hydrogen transport is currently prohibited through ten road tunnels in the UK based on its classification under the European ADR rules (carriage of dangerous goods by road). Reviewing hydrogen-specific ADR regulation, along with restrictions for ammonia and LOHCs, transport efficiency could be significantly increased. However, any changes to these regulations should be dependent on safety cases being proven.
- **Gas Safety Management Regulations (GSMR)**
  GSMR currently prohibit injecting more than 0.1% hydrogen in the networks. This will need to be updated to unlock the UK's linepack capacity. The UK Government will make a policy decision in 2023 on whether to allow blending of up to 20% hydrogen by volume into the gas distribution networks [16].

- **Planning and consenting barriers**
  Our research suggests that developers face a number of constraints surrounding the delivery of critical regulatory consents, particularly planning and environmental permitting. Delays around consenting can significantly extend the lead time of hydrogen storage projects. Some stakeholders suggested streamlining the Nationally Significant Infrastructure Project (NSIP) regime in England and accelerating the consenting process through increasing funding to relevant planning offices across the UK.

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12.2 Endnotes

[1] €128 and €132 per kWh converted to Pound sterling
[2] $1.54 per kg and $0.05 per kWh converted to Pound sterling
[3] Estimated based on the HyBrit project
[4] $1.23 per kg and $0.036 per kWh converted to Pound sterling
[5] $1.61 per kg and $0.048/kWh$_{(LHV)}$ converted to Pound sterling
[6] $65 per kilogram converted to Pound sterling
[7] $1000 dollars converted to Pound sterling
[8] $0.15 and $0.65 converted to Pound sterling

climateXchange
Scotland's centre of expertise connecting climate change research and policy

info@climatexchange.org.uk
+44(0)131 651 4783
@climatexchange_
www.climatexchange.org.uk

ClimateXChange, Edinburgh Climate Change Institute, High School Yards, Edinburgh EH1 1LZ