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Long Duration Energy Storage: Opportunities, Challenges and Solutions – Part II

By Harry K. Brunt*

In this two-part article, the author considers the challenges faced by countries such as the United Kingdom that wish to reduce their reliance on natural gas for heating by electrification using renewable power and the role of long duration energy storage (LDES) systems in meeting those challenges. In the first part, published in the prior issue of Pratt's Energy Law Report, *the author reviewed the challenges for de-carbonising domestic heating and whether LDES might offer a solution. Here, the author discusses LDES technologies, the duration and efficiency of storage, concerns for investors in and lenders to LDES projects, and green hydrogen solutions for large scale energy storage.*

LDES TECHNOLOGIES

The following paragraphs consider briefly the current technologies available for LDES, focusing primarily on batteries, pumped hydroelectric storage, compressed and liquid air energy storage and compressed hydrogen storage.

Conventional Battery Storage (Li-ion)

Despite a very substantial fall in the price of cells over the past 10 years, conventional battery storage using lithium ion (Li-ion) technology remains relatively expensive as compared with other bulk storage technologies, particularly when implemented at large scales, but at the smaller end of the energy storage and output capacity range is more competitive and offers certain advantages. Total project costs for Li-ion battery storage range between USD 393 and USD 581 per installed kWh of capacity, as compared with USD 106 to USD 200 for pumped hydro, according to World Bank figures.

Li-ion cells are not necessarily well-suited to long duration storage applications: they have a limited lifespan, depending on the number of charge and discharge cycles, and batteries also self-discharge slowly over time and the health of Li-ion batteries may be adversely affected if storage temperatures are not carefully controlled; battery energy storage systems also generally have to be cycled frequently to recover investments. Nevertheless, the government's LDES Technical Decision on the cap and floor regime (see below) did not exclude Li-ion batteries and 62% of the projects eligible for assessment for Window 1 of that scheme involved Li-ion solutions.

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Flow Batteries

A flow battery stores energy in two liquid electrolytes (one positive and one negative) in separate tanks, which are circulated across two electrodes, separated by a porous membrane, to generate power. Unlike traditional batteries that store energy in solid electrodes, flow batteries offer greater flexibility in scaling power and energy capacity (which can be separately adjusted, unlike dry cells), making them suitable for large-scale energy storage. Round-trip efficiency is 65-80%.

The most widely used chemistry is based on vanadium in different oxidation states on the two sides, but this creates a practical problem as vanadium is in short supply and is expensive. Alternative chemistries are being developed but are not yet commercialised.

Iron-Air Batteries

Iron-air batteries are mentioned in the 2030 Action Plan as a possible option for LDES. This battery chemistry uses iron as the anode and atmospheric oxygen as the cathode and involves the oxidation of iron during the discharge cycle and its reduction during charging, a process that is both reversible and capable of storing a large amount of energy. Their attractiveness lies in their ability to use abundant and non-toxic materials, presenting a sustainable and cost-effective alternative to Li-ion cells.

The technology is, however, also not yet commercialised and technical challenges hinder their widespread adoption. Scaling up production to meet global demand remains a significant hurdle, along with improving durability and cycle life, which remain the focus of research and development efforts.

Pumped Hydro

Pumped hydro storage uses electricity to pump water from a low to a high level reservoir. The stored water is released through turbines to generate electricity, converting its gravitational potential energy into electrical energy. Pumped hydro is a mature technology with a long history of worldwide deployment. Its round-trip efficiency is 78-81%.

There are currently four pumped storage hydro facilities, located in Scotland and Wales and commissioned between 1963 and 1984, with a combined storage capacity of 26.7 GWh and an output capacity of 2.8 GW, representing less than ten hours' worth of energy storage at full output power. Six new schemes are planned in Scotland, with a total output capacity of 3.9 GW and storage capacity of 95.8 GWh. If all were constructed, they would increase the UK's pumped hydro storage capacity to 122.1 GWh.

Green Hydrogen

In the case of hydrogen, a large portion of electrical energy is lost in electrolysis, treatment and compression of the gas and re-conversion to electricity (using fuel cells or combined cycle gas turbines):

- The efficiency of polymer electrolyte membrane (PEM) electrolysis is expected to reach 82 to 86% by 2030.
- To compress hydrogen to 200 bar pressure consumes 10% of the energy stored, and at 800 bar consumes 15.5%.
- A combined-cycle gas turbine power plant has a best case re-conversion efficiency of around 60%. A simple-cycle gas turbine, which is more likely to be utilised in this context, has a lower efficiency of 35% to 40%.

This gives a round-trip efficiency of well under 50%, which is much lower than pumped hydro storage. The Royal Society quotes a round-trip efficiency of only 41% (based on re-conversion using a fuel cell or 4-stroke engine), at which, for a given net energy output, 2.4 times the input electrical energy would be required. A higher round-trip efficiency might be achievable using a combined-cycle turbine generator, but it is still likely to remain below 50%, and combined cycle systems may not be practical for peaking power plants as they are more suitable for baseload generation given that they take an appreciable period of time to reach full efficiency.

The energy density of hydrogen by mass is 33.3 MWh per tonne. At 40% re-conversion efficiency using a simple-cycle power plant, to store 100 TWh of net energy output would require approximately 7,500,000 tonnes of hydrogen gas. If stored at 200 bar pressure and 20°C temperature, at a density of 15 kg/m^3, 7,500,000 tonnes would occupy a volume of 500 million m^3 (equivalent to 200,000 Olympic-size swimming pools).

Whilst this seems like a large storage volume, it is a small fraction of known theoretical storage resources in underground salt caverns in the UK, being the only proven technology for storing large volumes of pure hydrogen. One recent study estimated that there might be up to 2,150 TWh of theoretical hydrogen storage capacity in salt caverns in the UK, although subsequent analysis has suggested only 10% of this might be usable. Nevertheless, East Yorkshire alone has more than enough capacity to store 100 TWh of hydrogen.

Britain currently has underground cavern storage capacity for about 25 GWh of hydrogen and over 20 TWh of natural gas. A cluster of three 70,000 m^3 caverns used to store hydrogen on Teesside has been in operation since 1972.

A variation on green hydrogen is green ammonia, which can be stored as a liquid at relatively low pressure and has a volumetric energy density higher than liquid hydrogen and about half that of methane. Current production technology (primarily the Haber-Bosch process) is, however, not well suited to intermittent production and alternative technologies such as a catalytic electrochemical process remain inefficient and have not been commercialised. Direct synthesis remains subject to research and development and if commercially successful would be a game-changer.

Compressed Air Energy Storage

Compressed air energy storage (CAES), whilst less efficient than compressed hydrogen in volumetric energy density terms, is also under serious consideration as a LDES solution. Air is compressed using excess electrical energy and the compressed air can be run through a turbine generator to recover a portion of that energy. CAES has a round-trip efficiency of up to 56%, which is more efficient than compressed hydrogen storage.

A British Geological Survey[1] study identified 3,880 caverns suitable for compressed air energy storage with an estimated total volume of 1,830 million m^3 (1.83 km^3). It estimated that a CAES plant with a full charge of 10 caverns could store 25.32 GWh of energy, which could be converted to 23.19 GWh of work, requiring 43.27 GWh of energy to produce, reflecting the 54% round-trip efficiency. The Cheshire Basin could potentially support around 100 such CAES plants, giving a potential total exergy storage capacity of 2.53 TWh and a power output of 40 TW.

To mitigate the burden on the national grid, one could expect storage sites to be distributed around the UK to some extent, noting that there are large halite deposits in the Cheshire, East Yorkshire and Wessex basins. Some of these sites are already used for the storage of natural gas.

Liquid Air Energy Storage

Liquid air energy storage (LAES) involves using electricity to cool air (through compression and expansion) until it is liquid at atmospheric pressure and storing it in a well-insulated container, whereby it can be maintained cryogenically as a liquid for extended periods (potentially many months) with minimal losses, typically below 0.05% per day. To utilise the stored energy, the liquid air is heated, evaporated, expanded and run through a turbine generator. The initial compression and liquefaction process produces heat which in principle can be stored to be used in the evaporation process.

LAES offers a relatively high round-trip efficiency of 55-65% and is unconstrained by geological locations (which affect siting of CAES and

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[1] Parkes, D.; Evans, D.J.; Williamson, P.; Williams, J.D.O. Estimating available salt volume for potential CAES development: A case study using the Northwich Halite of the Cheshire Basin. J. Energy Storage 2018, 18, 50-61.

pumped hydro). At least one commercial-scale LAES facility is already operating in the UK and further facilities are planned.

Gravitational Energy Storage

Electricity can be used to raise large masses, increasing their potential energy. That energy is recovered over the discharge cycle as the masses are lowered, driving generators to create electricity. This technology is currently not deployed at large scale and remains under development.

Thermal Storage

Thermal storage systems are worth a mention, whereby high grade heat energy is stored in molten salts, solids, thermal oils, liquid metals or as steam or lower grade heat is stored in water or other materials. These systems really come into their own where district heating networks exist.

For example, water pit storage is deployed to provide district heating in Austria, Denmark and Germany. With a temperature range of 70°C, water can store 82 kWh/m^3 of thermal energy, with losses below 0.1%/day in large systems and achieving heat out/in efficiencies of over 90% for heat stored in late summer and delivered in winter.

Molten salts store heat in the range of 300-580°C and are currently used in concentrated solar power plants and could be used in conjunction with nuclear power plants to buffer output and render nuclear power more flexible.

Carnot batteries use resistive electrical heating to heat up and store heat at high temperature in solid materials such as concrete for later delivery as electrical power generated by a steam turbine. The Royal Society's study suggests, however, that whilst Carnot batteries are expected to be one of the cheapest large scale storage options, they will be more expensive than hydrogen storage without being much more efficient.

DURATION OF STORAGE AND EFFICIENCY

Storage systems with large capital costs per unit of energy stored have to be cycled frequently in order to recover the investment. Storage technologies can, therefore, be grouped into categories according to the typical time in which their contents must be cycled:

- Category 1: minutes to hours: conventional (non-flow) batteries;
- Category 2: days to weeks: flow batteries, advanced compressed air energy storage, Carnot batteries, pumped thermal storage, pumped hydro, liquid air energy storage; and
- Category 3: months or years: synthetic fuels, ammonia, hydrogen.

Conversely, efficiency and relative cost decreases from category 1 to category 3.

The Royal Society's study[2] concludes that a combination of advanced compressed air energy storage (ACAES) and hydrogen storage provides the benefits of the greater efficiency of the former and the relatively lower storage cost of the latter. While the study notes that the costs and efficiencies of large ACAES systems are poorly known, for a wide range of assumptions it found that combining ACAES with hydrogen would be likely to lower the cost relative to that found with hydrogen alone (by up to 5%, or possibly more), although not assured. When they are optimally combined, the capacity of ACAES is much smaller than that of hydrogen storage, but ACAES delivers more energy because it is cycled more frequently.

ADDRESSING CONCERNS FOR INVESTORS IN AND LENDERS TO LDES PROJECTS

Risks and Revenue Uncertainty

One might take the view that an LDES project offers an inherent arbitrage opportunity to buy excess electricity when it is cheap and sell it at a higher price when it is in high demand, creating a natural profit generation device. This is, however, overly-simplistic and ignores multiple risks and uncertainties, not the least competition from other LDES projects and the risk of over-supply of energy storage, changes in demand for electricity (which might be lower than expected), competition from interconnectors and assumptions about generation capacity being incorrect. As such, long build times combined with revenue uncertainty have inhibited investment in LDES development over the last 40 years.

Cap and Floor Support Scheme

Developers have, therefore, been lobbying for project revenue support and, in October 2024, following a consultation process, the government announced a decision to introduce a "cap and floor" investment support scheme with Ofgem acting as regulator and investment support scheme delivery body.[3] The scheme is similar to the cap and floor regime that supports interconnector projects, utilising a proven model that has successfully facilitated investment and is familiar to the market. Its objective would be to ensure investors receive a minimum amount or "floor" revenue to enable their investment in LDES assets, whilst the "cap" would provide returns to consumers for their support where LDES assets generate revenue above the cap.

[2] Large-scale electricity storage, September 2023.

[3] Long duration electricity storage consultation: Government Response (Department for Energy Security & Net Zero), October 2024.

In March 2025, the Department for Energy Security & Net Zero and Ofgem published a Technical Decision Document to confirm key details, in particular that:

- The cap will be set to allow recovery of invested capital (debt and equity) and to provide a fair return on investment if the assets perform well in the market; and
- The floor will be set to allow recovery of invested capital (debt and equity) along with a rate of return that is comparable to the cost of debt.

The government and Ofgem stated that they believe this sets the right balance of incentivising investment and encouraging appropriate operation of LDES assets, whilst avoiding unnecessary risk to consumers. Their initial position is also that LDES assets should be subject to the cap and floor regime for 25 years and that all capital costs would be recovered over this period. Ofgem may consider requests for different regime lengths, but any request for a shorter duration must be at least 20 years, because shorter durations are likely to result in higher floor levels, increasing potential consumer support in any year, as costs would be spread over a shorter period. LDES developers will be able to recover all economic and efficient capital and operational costs as long as they comply with their licence obligations (and subject to any incentive mechanisms which may reduce their recovery).

Following industry consultation, Ofgem has in September 2025 issued a decision to clarify details of the financial framework for the Window 1 cap and floor regime. The cap is proposed to be flexible (a "soft" cap), meaning that if revenues exceed the cap, the extra revenue is shared between the project licensee (as to 30%) and UK consumers (as to 70%). The floor would allow recovery of invested capital (debt and equity) and provide a return similar to the cost of debt for both equity and debt investors. Cap and floor values will be indexed based on an outturn inflation indexation method and cost of capital will be deflated using the Bank of England's target rate of 2%.

Ofgem has ruled out using a competitive approach for Window 1 of the cap and floor regime following stakeholder consultation as it concluded that this would add complexity and risk which could delay delivery of LDES infrastructure. It has therefore proposed an administrative approach for setting cap and floor rates for the first window.

To be eligible for support, LDES projects must have a minimum capacity of 100 MW (Stream 1, being currently limited to pumped hydro storage and Li-ion batteries) or 50 MW (Stream 2, comprising other less established technologies and likely to encompass flow batteries, LAES and CAES), must be able to output that amount of power continuously for eight hours and must be able to maintain this level of performance over the duration of the support period.

Ofgem published details of the eligibility assessment outcome for Window 1 of the LDES cap and floor scheme in September 2025. Its decision confirmed that 77 LDES projects would proceed to the project assessment stage, comprising 48 using Li-ion battery technology, 21 involving vanadium flow or zinc batteries and eight are other technologies (five pumped hydro storage projects, two proposing liquid air/battery energy storage hybrids and one using compressed air storage). It appears that the government's technical decision to set the minimum power output capacity for Stream 1 technologies (which include Li-ion batteries) at only 100 MW (to be sustained for at least eight hours) may have skewed the eligibility criteria towards favouring battery energy storage systems.

The project assessment phase is now in progress during and Ofgem and NESO aim to publish an initial decision list of projects offered cap and floor support in the spring of 2026.

The cap and floor scheme does not apply to hydrogen-based energy storage or generation projects. Separate business models are proposed for these technologies, as briefly discussed below.

Sources of Revenue for LDES Projects

LDES projects should, in principle, be able to generate three primary sources of revenues:

- Electricity price arbitrage, namely buying electricity when the price is low and selling stored electricity when prices are higher (taking into account the round-trip efficiency);
- Participation in the capacity market (CM), whereby power generators compete for contracts at auction with a duration of 1 to 15 years under which they are paid a charge for their availability to provide capacity and to deliver energy at times of peak demand, a mechanism which is intended to ensure that there is a reliable and secure generation capacity available to meet demand and to address the intermittency and unpredictability of variable renewable power generation and periods when the system is stressed, e.g., by cold snaps; and
- Provision of ancillary services (AS), including the Balancing Mechanism (BM),[4] redispatch and grid congestion management, voltage

[4] A real-time market where the Electricity System Operator (ESO) manages the electricity supply and demand balance on the British power grid.

support, frequency response/stabilisation, reserve services and black start capability.

Note that different LDES technologies have different response times and not all technologies are suitable to provide ancillary services that require instantaneous response, such as Fast Frequency Response (FFR).

Many respondents to the government's consultation on LDES in 2024 suggested that beneficiaries of the cap and floor scheme should be allowed to participate in other electricity markets such as the CM, as well as participating in the BM and earning revenue from other ancillary services, potentially allowing "revenue stacking." Many argued that such wider participation would facilitate maximisation of revenues and diversification of revenue streams, reducing the risk of revenues dropping below the floor and then accordingly minimizing the potential cost to consumers.

A number of respondents highlighted that the electricity interconnectors scheme allows recipients to participate in the CM while receiving cap and floor support. Some, however, recommended that LDES projects only be allowed fettered access, such as only being permitted to compete for one-year contracts, and to be required to be a price taker (whereby capacity providers cannot exit the auction until the price drops below the price-taker threshold).

A small number of respondents disagreed with allowing LDES assets to participate in the CM as it could cause distortions to the auction prices, as they might be able to submit lower prices than other assets due to the support provided by the cap and floor. Some respondents felt that recipients of the cap and floor scheme should only be able to access the balancing mechanism and ancillary services markets.

In its response to the consultation published in October 2024, the government has confirmed that it intends to allow access to the CM, subject to considering what parameters around such participation should apply.

It is interesting to note that Zenobē Energy Limited has applied to the UK's Competition Appeal Tribunal to challenge the decision of the Gas and Electricity Markets Authority to support longer-duration energy storage projects on the basis that it was a subsidy decision under the Subsidy Control Act 2022, alleging that it was not validly made and should be quashed. Zenobē contended that the cap and floor scheme's design risks distorting competition by enabling supported LDES projects to compete directly with unsupported short-duration energy storage (SDES) assets, such as lithium-ion systems, which have historically operated without public financial support. Their application stated that SDES providers rely on revenue stacking across multiple markets to attract investment and maintain commercial viability. By allowing LDES projects to access these same markets while benefiting from cap and floor support, they alleged that the cap and floor scheme will create an uneven playing field that would undermine the investment case for SDES technologies.

HYDROGEN PRODUCTION, STORAGE AND POWER GENERATION

A discussion of hydrogen-based energy systems is complicated because clean hydrogen production in the UK is expected to be developed at scale initially based predominantly on blue hydrogen (derived from natural gas through steam reforming, coupled with capture and storage of the carbon dioxide produced as a by-product) with green hydrogen production (through electrolysis) being an alternative parallel or future expansion pathway. Clean hydrogen infrastructure development is also expected to comprise multiple use cases, including potentially blending into natural gas for heating (but only as a last resort where a producer has insufficient customer load), industrial consumption and transportation applications, as well as hydrogen to power (H2P).

Hydrogen technologies cannot, therefore, be considered in the same manner as LDES in the UK and represent a more complex and special case.

The government has proposed a series of "business models" to support the development of hydrogen production, storage, transportation and hydrogen to power, as well as carbon capture utilisation and storage (CCUS) projects including both transportation and subterranean storage of CO2 (which are expected to be based on a Regulated Asset Base model) and CCUS-abated gas to power projects.

Hydrogen Production Business Model

The government has proposed a hydrogen production "business model" which will provide revenue support to hydrogen producers to overcome the operating cost gap between low carbon hydrogen and high carbon fuels, being designed to incentivise investment in low carbon hydrogen production and use. This will be implemented through a "Low Carbon Hydrogen Agreement" which includes elements which are similar to the contracts for difference (CfD) regime applicable to low carbon electricity and the dispatchable power agreement (DPA) methodology applicable to CCUS-abated gas to power projects, with the intention of providing price certainty to the hydrogen producer.

Hydrogen Transport and Storage Business Models

In the British Energy Security Strategy, the government committed to designing, by 2025, new business models to stimulate investment in hydrogen transport and storage infrastructure, which it considered essential to grow the hydrogen economy. These business models are expected to mitigate demand risk through external subsidy by providing revenue support under a contract between the infrastructure provider and a government-appointed counterparty, establishing a minimum (probably annual) revenue "floor," irrespective of the extent to which a facility is used. A revenue "cap" or "gainsharing" arrangement might also apply.

Alongside revenue support contracts, the government also considers that the hydrogen transport business model might also incorporate a Regulated Asset Base (RAB) approach to facilitate and support the financing of hydrogen pipeline projects.

Proposed Hydrogen to Power (H2P) Business Model

NESO considers lower carbon dispatchable technologies such as H2P to be important for achieving a clean power system, reducing reliance on weather-dependent renewables and over the long-term replacing the need for unabated gas power generation. NESO has estimated that the GB electricity system could need around 40-45 GW of long duration flexible capacity by 2030.

Between December 2023 and February 2024, the government ran a consultation on the need for, and potential design of, a market intervention to support the deployment of H2P projects. External analysis, published alongside the consultation, indicated that while some H2P plants in specific circumstances with relatively easy access to low carbon hydrogen fuel could come forward, market conditions meant that a full range of H2P plants would struggle to be deployed. Two key inter-linked barriers were identified, namely uncertainty and increased investment risk from H2P being a new technology and dependence on nascent critical enabling infrastructure, i.e., hydrogen production, transport, and storage creating 'cross-chain risks', and hydrogen fuel supply risks.

In its consultation response document published in 2024, the government committed to introduce a "business model" to support deployment of H2P projects (the H2P BM). The H2P BM is expected to be based on elements of the CCUS-abated gas to power DPA-style business model, adapted to suit the needs of H2P. During 2025, the government plans to present more detail on the proposed design of a bespoke H2P BM and to undertake a further market engagement exercise to invite feedback on those plans.

CONCLUSIONS

It is clear that long duration energy storage systems will play a key role in facilitating decarbonization by optimising electricity generation and supply arrangements, taking into account increased reliance on renewables. The UK is already forging ahead with the expansion of LDES capacity as well as clean hydrogen infrastructure (including hydrogen storage) and has taken steps to set up support arrangements to make projects more attractive to investors and their lenders. We may expect similar incentives or alternative revenue support schemes to be adopted worldwide over the next few years.