Renewable and Sustainable Energy Reviews 159 (2022) 112240

Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

Evaluating emerging long-duration energy storage technologies

Rui Shan [a], Jeremiah Reagan [b], Sergio Castellanos [c], Sarah Kurtz [b], Noah Kittner [a,d,*]

[a] Department of Environmental Sciences and Engineering, Gillings School of Global Public Health, University of North Carolina at Chapel Hill, NC, USA
[b] Materials and Biomaterials Science and Engineering Graduate Program, University of California, Merced, CA, USA
[c] Department of Civil, Architectural and Environmental Engineering, University of Texas Austin, TX, USA
[d] Department of City and Regional Planning, University of North Carolina at Chapel Hill, NC, USA

ARTICLE INFO

Keywords:
Long-duration energy storage
Electricity market
Use cases
Land-use footprint
Average capital cost
Equivalent efficiency

ABSTRACT

We review candidate long duration energy storage technologies that are commercially mature or under commercialization. We then compare their modularity, long-term energy storage capability and average capital cost with varied durations. Additional metrics of comparison are developed including land-use footprint and equivalent efficiency based on idle losses to account for emerging long-duration storage applications and use cases. The technology landscape may allow for a diverse range of storage applications based on land availability and duration need, which may be location dependent. These insights are valuable to guide the development of long-duration energy storage projects and inspire potential use cases for different long-duration energy storage technologies. This analysis also lays the foundation for future relevant modeling and decision-making studies that implement emerging long-duration energy storage.

1. Introduction

To mitigate climate change, there is an urgent need to transition the energy sector toward low-carbon technologies [1,2] where electrical energy storage plays a key role to integrate more low-carbon resources and ensure electric grid reliability [3–5]. Previous papers have demonstrated that deep decarbonization of the electricity system would require the development of long-duration energy storage (LDES) to serve extended periods of reduced generation capacity or seasonal energy supply shortages [6–9]. Dramatic reductions in cost for solar and wind now imply that improvements in storage could be the remaining key to unlock low-carbon electricity worldwide. Planned and emergency outages, such as those encountered recently in places with increased intermittent renewable energy such as California and Australia, draw more attention to the value of long-duration energy storage. Although this hypothetical value is widely discussed [6,7], a systematic review can provide an understanding of the level of technological maturity relative to what is needed by the power grid to achieve deep decarbonization at a reasonable cost. This analysis details technological maturity across different quantitative parameters to identify roadblocks, challenges, and opportunities to accelerate deployment of long-duration storage technologies.

There is no general consensus definition on LDES. Entities like the California Public Utilities Commission define LDES technology as an electric energy storage technology that can stably discharge electricity at rated power for no less than 8 h [10]. However, such definition ignores the duration of holding the electricity for longer periods of time, which could be essential to provide services like seasonal storage. In this paper, we loosely define long-duration energy storage technologies as ones that at minimum can provide inter-day applications. Long-duration energy storage projects usually have large energy ratings, targeting different markets compared with many short duration energy storage projects. The large energy rating raises concerns about the footprint measured in m^2/MWh. Additionally, when energy is stored for a long period of time, the idle losses or self-discharge rate becomes critical for storage technologies. These characteristics are not discussed in previous reviews that focus more on comparisons of short duration storage technologies [11–14].

In contrast to short-duration energy storage technologies, where Li-ion batteries are projected to dominate by 2030 [15,16], the market for LDES technologies contains a more diverse set of competitive players, ranging from traditionally dominant storage technologies such as pumped storage hydropower and compressed air storage, to emerging technologies from startups which are not usually included in

* Correponding author. Department of Environmental Sciences and Engineering, Gillings School of Global Public Health, University of North Carolina at Chapel Hill, NC, USA.
E-mail address: kittner@unc.edu (N. Kittner).

https://doi.org/10.1016/j.rser.2022.112240
Received 12 July 2021; Received in revised form 28 January 2022; Accepted 4 February 2022
Available online 17 February 2022
1364-0321/© 2022 Elsevier Ltd. All rights reserved.

battery-dominated discussions. These LDES technologies differ not only in duration from the short duration energy storage technologies, but also differ significantly in their design features and fundamental properties. In particular, many LDES technologies cross-sectors in their use cases – and could provide solutions for electricity storage, transportation, heat, and agriculture [17]. Many LDES technologies are under early-stage development and could significantly improve their performance in the next few years. We present firsthand data about these emerging technologies by working closely with investors and startups who commercialize them. Omission of these emerging technology types hinders a proper evaluation of the role of LDES technologies [18]. Perpetuating the stereotype that long-duration storage technologies are inefficient, geographically constrained, and prohibitively capital intensive does not fully describe the use-cases in which they may become critically needed as part of a larger decarbonization strategy.

Furthermore, in a large-scale transition to decarbonized electricity, many old thermal power plants and large generators will become obsolete – either due to their significant emission factors or not being economically viable. This analysis also considers the role of long-duration storage technologies as potential replacements for existing conventional generators and the areal requirements for long-duration energy storage. For some technologies, long-duration storage could offer an attractive transition to offset potential jobs losses or revenues lost from outdated equipment and aging infrastructure.

This paper reviews emerging LDES technologies, compares their techno-economic characteristics and discusses potential use cases based on innovative features. The results provide valuable insights to economists, system modelers, policymakers and investors on the pathway to assess the deep decarbonization of the electricity system.

2. Long duration energy storage technology evaluation

2.1. Methodology

In selecting which technologies to compare, electricity-in-electricity-out technologies were prioritized. Energy storage technologies can also couple with CO_2 sequestration [19] and fuel production crossing several different sectors [20], but we would render such applications at lower priority in this review since they are difficult to compare based on the targeted metrics of land footprint, equivalent efficiency, and average cost if providing non-electricity based services. We chose to focus on technologies applicable to diurnal, cross-day, or even seasonal storage. We review technologies that are commercially viable or in the commercialization process. Recent technology improvements found in laboratories are not included and we would refer readers to other review papers [21,22] for related information. Lithium-ion storage represents a benchmark for a “standard” new utility-scale battery installation because Li-ion is commonly used for short-duration storage, but also capable to provide inter-day storage services. Some mature technologies like lead-acid batteries [23] and pumped storage hydropower could also serve as benchmarks but there are a limited number of these projects in the development pipeline compared to Li-ion projects [24].

Surveys were sent to companies identified as actively developing relevant technologies, asking for estimates of costs and performance metrics typical of a system marketed to customers. We also requested minimum and maximum deliverable sizes and the associated marginal costs. Companies agreed to meet and provide additional details through correspondence. These survey data were supplemented by a literature search that prioritized recent publications (2015 or later) to provide a more complete view of the current state of technologies and focused on real-world examples of operational projects rather than theoretical simulations, specifying current costs and performance rather than future projections. To be comprehensive in our data-capturing process, land footprint data of some projects (e.g., compressed air and concentrated solar) were estimated using Google Earth on locatable projects, ignoring underground infrastructure.

In the technology comparison, we focused on the subset of emerging technologies that have at least one demonstration project. We use a modeled Li-ion system [25] as the cost benchmark for comparison. To gauge the effectiveness of storage on the scale of days or weeks, we compute the equivalent efficiency, a value that considers both roundtrip efficiency and idle losses, by using Eq. (1). Some companies also provided information about their reference systems which are either typical, nominal, or useful configurations in demonstrating their technologies. Based on the reference system, we calculate how the project average capital cost, C_x, (\$/kWh), evolves with different energy ratings for a power rating (Eq. (2)). To make a fair comparison and to protect the companies' cost information, we divided the project average cost based on a system with an energy to power ratio (kWh/kW) of 4 h. This configuration considers the possible practice of Li-ion battery projects and it is also a requirement for energy storage to gain resource adequacy credits in the California market. If not specified otherwise, the cost is converted into 2021 USD based on US inflation rate and exchange rate between EUR and USD as 1:1.15.

$$\textit{Equivalent efficiency}\ (x) = \textit{Round trip efficiency} \times (1 - \textit{idle loss per hour})^x \tag{1}$$

where x is the storage time (hour).

$$C_x = \frac{E_r \times C_r + (E_x - E_r) \times C_{mar}}{E_x} \tag{2}$$

C_x is the project average cost (\$/kWh) of the estimated system. The estimated and reference systems have different energy ratings, but the same power ratings.
E_x is the energy rating (kWh) of the estimated system
E_r is the energy rating (kWh) of the reference system
C_r is the average cost (\$/kWh) of the reference system
C_{mar} is the marginal energy cost (\$/kWh) of the system with a fixed power rating

Levelized cost of storage (LCOS) is a widely used metric. However, it involves many underlying assumptions on number of cycles and capacity factor, making LCOS not so comparable for different durations of storage-since the inherent services provided by a storage application could differ. Even for previous research comparing the cost across long duration storage technologies, the supplied LCOS values could be misleading. For example, Hunter et al. [26] computed LCOS by assuming the capacity factor was associated with the round trip efficiency. However, this article ignored the fact that if the system holds energy for a long duration, the system with the same round-trip efficiency will result in a different equivalent efficiency, and in turn a different capacity factor, resulting in different cost of energy stored or delivered.

2.2. Technology overview

In this section, we summarize emerging LDES technologies that are commercially mature or under commercialization and use different mediums and drivers to operate (i.e., gravity, water, solid weight, compressed air, heat, chemicals, gases).

2.2.1. Mechanical storage using water

Conventional pumped-storage hydropower (PSH) is composed of two reservoirs with elevation difference and at least one powerhouse, storing the energy in the form of gravity of the water. Currently, PSH occupies more than 90% of the US energy storage market [27] and its economical resource potential exceeds the global energy storage requirement based on recent studies [28,29].

Similar to other LDES technologies, the cost can be separated into energy and power components. The energy component includes the cost to construct the reservoir, which determines how much energy it could store. The power part mainly concerns the powerhouse. The capital cost varies significantly – the cheapest could at minimum, comprise one-fifth of the most expensive one. If measured in \$/kW power capacity, PSH is expensive compared to other technologies [30,31], but is among the cheapest if measured by \$/kWh capital cost [16,31–33]. Some researchers believe PSH could reach 5\$/kWh [34]. Past studies [16,31–33, 35] state that PSH is one of the most cost attractive options for LDES in the next 10 years. Such a low energy cost results from the large energy rating. Some projects are designed for seasonal storage or to store energy over multiple years [36]. Additionally, it would be expensive to build a small PSH project due to project-level economies of scale.

In addition to low energy costs, PSH also has many other advantages [37]. The designed lifetime usually exceeds 30 years and sometimes lasts more than 100 years. The round-trip efficiency is relatively high at 65%–85%. The depth of discharge could reach 100% at its maximum. Another advantage, especially for LDES technologies, is its low self-discharging rate [38]. Despite so many advantages— traditional PSH remains limited in deployment due to its dependence on water availability and geographic conditions, large land area, huge upfront capital costs, and considerable site-specific environmental impacts [39].

Emerging PSH technologies address some of these limitations. Instead of constructing a reservoir, a team designed a vessel and deployed it under water [40]. It would consume electricity to pump out the water from the vessel and generate electricity when water flows inside. The concept has been proven to be technologically feasible with a pilot project [41]. One researcher estimated the capital cost around 500–700 \$/kWh [42]. Researchers developed a similar concept in which a floating membrane would act as a storage reservoir rather than a vessel [43].

Another approach to reduce the cost of the reservoir is to utilize existing reservoirs, like a decommissioned coal mine. A case study on an underground mine site in Kentucky found that the initial capital cost would be between 1900 \$/kW and 2700 \$/kW for a 5MW/50 MWh PSH project [44]. Another assessment of a coal mine in Germany resulted in a capital cost of 300 \$/kWh when the head was 1000-m [45]. Depending on the driving factors, the underground environment can increase or decrease the round-trip efficiency compared with the traditional PSH projects [46,47]. Quidnet Energy, a geomechanical PSH provider, utilizing the pressure among subterranean rocks, had four projects under development in 2020 in New York, Texas, Ohio and Alberta [48].

The PSH technologies mentioned above still face geographic restrictions. Other teams have conceptualized a system that combines pumped storage with a compressed air system through a pressurized water container [49]. A realized example is Ground-Level Integrated Diverse Energy Storage (GLIDES) developed in Oak Ridge National Laboratory [50]. The current prototype of GLIDES uses a steel pressure vessel, leading to high capital cost. It costs around \$4700/kWh for a 300-MW, 6-h system. If the vessel is made of high-pressure pipe segment, the cost of the same system can be reduced to \$260/kWh [51].

2.2.2. Mechanical storage using solid weight

One drawback of PSH is the low energy density as it is constrained by the density of water. PSH essentially stores electricity in the form of gravitational potential energy. Using similar principles, some other gravity-based energy storage solutions are developed, increasing the energy density of storage media and alleviating water availability constraints, which are increasingly expanding in both magnitude and space, rendering alarming and unprecedented droughts [52].

In an underground PSH project, replacing part of the water with a heavy piston, we get the Gravity Power Module proposed by Gravity Power (Fig. 1a). A similar design is also under development by Heindl Energy. When the piston drops, it pushes the water through the penstock to move the turbine and generate electricity. Lifting the piston up through the hydraulic system consumes electricity. Gravity Power has begun a demonstration project in Germany. A Scottish company, Gravitricity, devised another underground gravity storage system, replacing the hydraulic system with winches (Fig. 1b). Their technology utilizes the existing mine shafts to raise and release the heavy weights up to 12,000 tons as the developer estimated [53]. Operation of a 250 kW demonstration unit commenced in 2020 and a commercial scale project, 4 MW is planned in 2021. Renewell is developing the similar technology as Gravitricity, with special focus on inactive oil and gas wells. Raising the mine shaft above ground, engineers from Energy Vault designed a tower, which uses a crane to lift blocks (Fig. 1c). Both the width and the height of the tower decide the energy capacity. The power output depends on the velocity and the mass of the block. Energy Vault began operation of a 5 MW/35 MWh commercial demonstration unit in Switzerland in 2020 with an energy density of 6.3 kWh/m^2 [54]. Also lifting blocks, a Russian company Energozapas (Fig. 1d) is developing a similar solution and has operated their prototype since 2017. Instead of vertical movement, Advanced Rail Energy Storage (ARES) uses a rail to move weight up and down a mountain (Fig. 1e). ARES has already completed a demonstration project in California and a 50 MW commercial project in Nevada is under development [55].

Compared to traditional PSH, these novel gravity-based technologies have many advantages [59], for example, the modularity. Their size can range from 100-kWh to multi-GWh, resulting in smaller footprints and

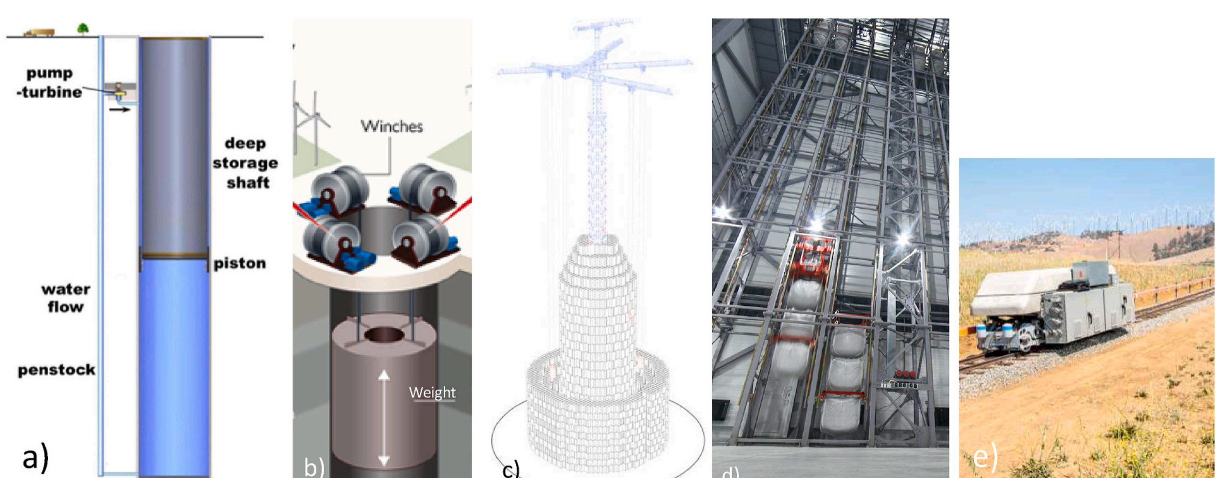

Fig. 1. a) illustrative plot of Gravity Power Module from Gravity Power Inc. [56]; b) Schematic plot of the Gravitricity system [53]; c) Design from Energy Vault [54]; d) Lifted Weight Storage module constructed by Energozapas [57] e) ARES's demonstration project in California [58].

environmental impact. The faster response time is another advantage. Gravitricity claims that their technology could ramp from zero to full power in less than 1 s [53]. ARES plans to actively participate in the frequency regulation market in CAISO [58], confident in their fast response time. Since there is no evaporation, as with PSH, the self-discharge rate or the energy loss during the storage is extremely low, making them an ideal candidate for long-duration energy storage.

Gravity Power's system is estimated to have a capital cost around 1800 \$/kWh [60] for a 4-h project. As for a similar 8-h duration project, another researcher estimated the capital cost as 158\$/kWh [61]. Both studies concluded a low levelized cost of storage around 160\$/MWh. The main cost component for these underground projects is the excavation cost, making more than 50% of the total capital cost [62]. Thus, if a prospective site is identified, such a technology could be highly cost-competitive, depending on the suitability of land. The capital cost of ground level gravity storage technology does not depend much on the site, but the marginal cost relies on the cost of building stock. Energy Vault estimated its marginal cost as \$37/kWh when the building stock is about \$10/ton. However, in 2020 US market, the price of cement is around \$120/ton and sand hovers around \$9/ton [63], making it challenging to arrive such a low marginal cost unless less expensive materials are utilized.

2.2.3. *Mechanical storage using compressed air*

Compressed Air Energy Storage (CAES) uses energy to compress air into a large underground cavern. The air is later released into a recuperator and heated for re-expansion at a turbine for power generation. CAES can be categorized into diabatic and adiabatic. In diabatic, the heat released by compression is not captured, and the reheating of air must be accomplished via burning of natural gas or through electric heating. Adiabatic systems capture the compression heat reuse in a recuperator, increasing efficiency for higher build cost. The last diabatic system in operation was built in 1991 in Mcintosh, Alabama, and though Apex is planning a project in Texas, it is designed to use natural gas for reheating. The rest future development of compressed air technology appears to be focused on the adiabatic version.

Adiabatic CAES (A-CAES) similarly relies on underground caverns. The use of hard rock excavation techniques allows for significantly more flexibility compared to natural salt caverns [64]. The reuse of compression heat results in efficiencies of up to 60–75% [11,31,65] (with Augwind claiming possibly 75–81% for their pilot [66]), at increased capital cost. Limited economic analysis of A-CAES has been publicly available. Adiabatic systems should also favor large builds, though possibly limited by the availability of land for siting large facilities and market interest in longer duration projects. After completion of their Toronto Island Demonstration Facility in 2015, Hydrostor (Fig. 2) opened their Goderich facility (1.75 MW and 10 MWh) to commercial service in 2019 in Ontario, Canada. Augwind announced a 5 MW/20 MWh pilot in Israel. Though early system sizes are small compared to diabatic systems, Hydrostor has a 500 MW/4 GWh project under development in Rosamond that could start by 2026 [64,67].

There is a third category that can be considered an offshoot of CAES, or a hybrid with Thermal Storage, called Liquid Air Energy Storage (LAES), sometimes called cryo-storage. Air is cooled to cryogenic temperature using a cycle of compression, cooling and expansion with associated hot and cold storage tanks. Highview is currently the only company with any LAES plants in operation. A 350 kW, 2.5 MWh pilot underwent testing between 2011 and 2014 and has since been relocated to the University of Birmingham. The 5 MW, 15 MWh Pillsworth Demonstration Plant in Bury, Greater Manchester began operation in April 2018. A number of plants are under development in the United States and Europe, the first of which is a 50 MW/250 MWh project under construction in Carrington, UK [68]. Highview reports plans for 4 GWh of plants [69].

LAES allows for higher energy density compared to diabatic and adiabatic CAES [70], and removes the cavern restriction in favor of tank

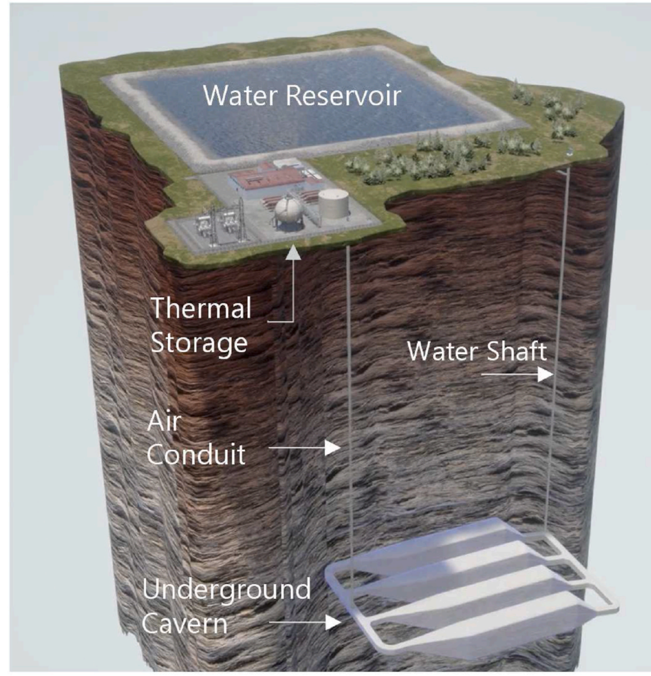

Fig. 2. Adiabatic CAES system developed by Hydrostor.

storage, for greater capital costs and O&M costs comparable to conventional CAES [71]. Round-trip efficiency is ~60%, though could climb to 70% with integration of waste heat recovery if built into existing power plants [71].

2.2.4. *Thermal energy storage*

Thermal storage can be sorted into three categories based on storage medium. Sensible Heat stores energy in the temperature of a material, later drawing it out through an exchanger to generate power via steam production or the expansion of another working gas/fluid. Latent Heat storage, frequently called Phase Change Materials (PCM), utilizes a phase transition of its storage medium, reverting it to release heat, and can be further manipulated by imposing pressure conditions. Thermochemical Storage drives an endothermic chemical reaction, splitting a molecular substance into products that are stored separately and reintroduced to reverse the reaction and release heat. Energy density of each storage type depends on the medium used, but ranges from 10 to 50 kWh/ton for sensible heat, 50–150 kWh/ton (50–200 kWh/m^3) for PCM, and 120–250 kWh/ton (200–600 kWh/m^3) for thermochemical [72]. After analyzing the Global Energy Storage Database hosted at Sandia National Laboratory [24], we found that most thermal projects to date are not designed for electricity storage. PCMs feature heavily in construction materials for energy efficient buildings for temperature regulation [72]. Only a few commercial thermochemical storage technologies are in development at this time like HiT Nano and TEXEL Energy storage.

Thermal storage for electricity generation is dominated by sensible heat molten salt, accounting for 77% of all thermal energy stored [12]. This is almost entirely implemented as Concentrated Solar Power (CSP), with typical duration of 4–10 h [24]. As CSP turns solar energy directly into stored heat for conversion into electricity, this does not represent a true electricity-in-electricity-out system. Some storage technologies require auxiliary loads (AC-based) to operate (e.g., pumps, fans, controls), and hence to fully integrate the storage technology with the AC electric grid, a relevant efficiency metric to consider is its AC-to-AC roundtrip efficiency.

AC-to-AC thermal storage systems are relatively new. Systems in which a working gas/fluid is circulated between hot and cold tanks are referred to as Pumped Heat Electrical Storage (PHES). Isentropic finished their 600 kWh, 150 kW Newcastle University demonstrator facility in 2019. It pumps argon between two tanks of mineral gravel and achieved an AC-to-AC roundtrip efficiency of 60–65% (with theoretical 75–80%). Analysis and cost estimates for a theoretical commercial system of 16 MWh and 1.6 MW, based on data from the project then in progress [73], and using an assumed efficiency of 67% scenarios, predicted storage costs of $18/kWh.

National Renewable Energy Laboratory (NREL) is working on their ENDURING project, in which sand storage medium is circulated between tanks and passed through a fluidized bed heat exchanger. The 405 MW and scalable 100 MWh – 76 GWh system claims energy densities of 450 kWh/m3, 10–100- hour duration, 50% roundtrip efficiency, and estimated storage cost of $10 - $40/kWh. The storage cost includes power system, while 10$/kWh is based on 100-h storage estimation, and $40/kWh is based on 10-your storage estimation. The cost estimates were based on basic equipment cost of materials and manufacturing, and may leverage site and building of a pre-existing thermal plant. The modular nature of heating elements allows for broad scalability of charge time.

Malta is developing a grid-scale 100 MW pumped heat energy storage (PHES) system leveraging mature technologies from established OEMs in the heat exchanger and turbine industries and the experience of Concentrated Solar Power(CSP) [74]. The initial system has 10 h for storage as an initial design target. The Malta PHES is highly modular in that the charge power, discharge power and storage duration can be adjusted independently for different use-cases.

Siemens developed its Electric Thermal Energy Storage (ETES) system using volcanic rocks for both heat-to-heat storage and heat to electricity via steam generation (Fig. 3). Having completed a 130 MWh demonstrator in Hamburg in 2019, they are currently working on the first series of commercial pilots. This technology has three modes to be deployed: 1) by the side of solar and wind to stabilize the output; 2) by the side of thermal plants to increase flexibility; or 3) to retrofit an existing thermal plant into a thermal storage system.

Another sensible heat, but non-PHES system is being developed by Antora Energy. Their thermophotovoltaic (TPV) system allows the medium to emit energy as light in the infrared and near-infrared wavelength to be absorbed by a photovoltaic cell, while other wavelength are reflected.

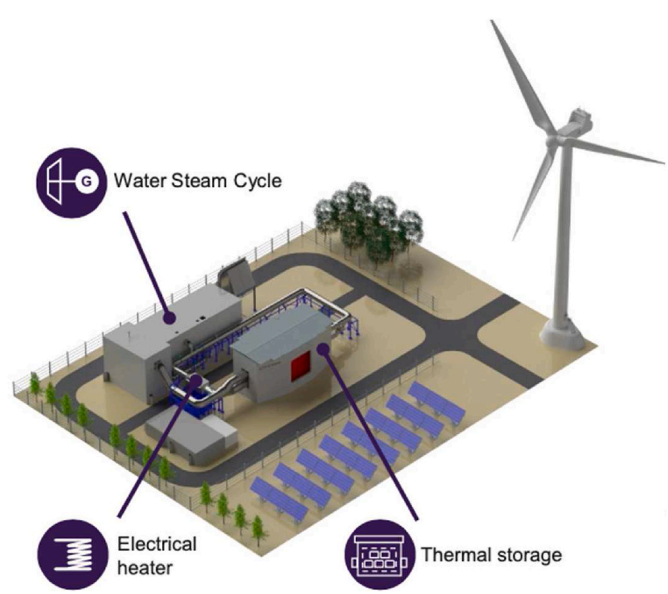

Fig. 3. Schematic of ETES system.

2.2.5. Flow battery

Flow batteries have the potential to provide flexible long-duration storage as they can be configured in different arrangements based on power and energy needs. Flow batteries have been under development for decades, yet renewed interest due to technological breakthroughs and cost reductions in solar and wind have renewed interest in a separation of power and energy components that cannot be achieved with lithium-based batteries. Compared to conventional stationary batteries, flow batteries separate power density from energy capacity and duration by design. Flow batteries could discharge MW-scale power within seconds. Unlike supercapacitors or other short-duration competitors, flow batteries can also serve the 8+ hour duration range with energy capacity a function of the electrolytic tank volume. The ability to substitute different electrolytic, membrane, and electrode materials make flow batteries an innovative technology for commercialization and deployment by experimenting with different chemistries and materials. Vanadium-redox flow batteries have demonstrated recent cost reductions and commercialization in the UK through companies such as Invinity Energy Systems that deploy standardized stacks housed in shipping containers. A majority of their projects serve off-grid and micro-grid markets, but flow batteries are increasingly connected to the grid. Zinc-based flow batteries such as zinc-air, zinc-cerium or zinc-bromine offer alternative options, though typically at lower efficiency and more degradation compared to vanadium-redox flow batteries. Zinc8 as a leader in zinc-air technology has energy storage projects underway in New York State to showcase commercialized solutions. An Australian company RedFlow commercialized zinc-bromine flow battery and could provide as small as 10 kWh systems. Additionally, lab breakthroughs identify future potential for organic, metals-free, quinone-based systems [75]. In Germany, Jena batteries in Germany offers organic commercial options with capacities up to 40 kWh. Iron-flow batteries such as those developed by ESS Inc, an American flow battery company, offer portability and transportability as key advantages for projects that require mobility-such as temporary micro-grids or other portable long-duration applications.

Power densities for vanadium-redox flow batteries (60–100 W/L) typically exceed those of other chemistries (50 W/L for zinc-based systems) and low power densities for metals-free options. Additionally, most flow batteries operate between 0 and 40 °C. Vanadium is a highly persistent metal with a cycle-life that potentially can exceed more than 10,000 cycles of 100% Depth of Discharge, making it an attractive option due to its extended lifetime (20+ years) compared to other flow batteries – and roundtrip efficiencies are reported up to 85% [76,77]. Past studies indicate fewer GHG emissions per kWh from flow batteries storing solar and wind compared to CAES [76].

As a long-duration option, flow batteries present interesting advantages compared to stationary battery counterparts such as lithium-ion storage and sodium-sulfur batteries. Due to their fast response times, flow batteries typically could provide load balancing, peak shaving, frequency response, voltage regulation, and ancillary service provision on the grid – yet at the same time they could expand volumetrically to increase total duration. Therefore, they may add flexibility depending on their grid application. They may charge or discharge from receiving the signal within seconds-to-minutes, and allow for black start capabilities for small micro-grid back-up – providing resilience during emergency outages or as a replacement for building generators. Conventional lead-acid or lithium-ion batteries that may cost less upfront capital than flow batteries, may degrade faster than vanadium- or zinc-based flow batteries on the market and yet are not able to provide 8+ hour storage durations. Primus Power, a flow battery developer, often points to the lower total cost of ownership as a key advantage compared to lithium-ion, though the market for 8+ hour storage is only beginning to emerge. Therefore, durability and the ability to locate flow batteries in most geographic locations make them a viable long-duration storage candidate—although they typically operate on smaller scales and shorter durations than other options considered in this study.

2.2.6. Power-to-gas

Power-to-gas has emerged as a potential way to convert electricity into gas, such as hydrogen, for heat or transportation. The major advantages are the opportunities for large-scale and long-duration storage that gas provides – and the potential for sector coupling across electricity, gas, transportation, and heat networks.

Historically, major barriers to implementing Power-to-gas have been low conversion efficiencies and high costs of electrolysis that limit deployment. Power-to-gas technologies include the conversion of electricity into hydrogen using water electrolysis (Power-to-Hydrogen). Hydrogen can be used for industrial purposes as a chemical, injected and blended with natural gas in existing pipelines, or stored. It can be later reconverted to electricity using a fuel cell or remain as hydrogen gas. Synthetic natural gas such as methane can be produced when hydrogen reacts with CO_2. This synthetic natural gas can be injected into the natural gas pipeline or stored and used to produce power in a gas turbine.

Currently, only 4% of global hydrogen production comes from water electrolysis – and a small fraction of electrolyzer-produced hydrogen is from renewable sources [78]. Two main electrolysis technologies are commercially available: alkaline (AEL) and polymer electrolyte membrane (PEM) [79]. Solid-oxide electrolysis cells are under development, as some companies such as LG and FuelCell Energy have built demonstration projects [80].

The greenhouse gas footprint of hydrogen production depends heavily on the type of electricity sourced to produce hydrogen. Alkaline and PEM electrolysis with electricity from wind and/or solar PV plants lead to substantially lower life-cycle CO_2-equivalent emissions for a comparable amount of hydrogen produced by other electricity sources.

Globally, the largest Power-to-Gas installations exist in Europe, particularly Germany, Denmark, and Switzerland [81]. As of 2017, the largest installed industrial plant was ETOGAS- Audi e-gas plant in Werlte, Germany, using 14.4 MW of electricity from offshore wind to power a 6 MW AEL electrolyzer. The hydrogen in this application combines with CO_2 from a biomethane plant to generate synthetic natural gas. The waste heat from electrolysis and methanation can supply heat to neighboring customers and the plant is eligible and participates in ancillary service markets in Germany. German power and gas grid operators have announced larger projects, such as 100 MW facility in Lower Saxony. The plant aims at reducing curtailed wind electricity, stabilizing the electric grid, and reducing need for new generation.

AEL electrolyzers have lower installation cost compared to PEM electrolyzers. Because AEL electrolyzers have a lower minimum operating capacity of 20% and slow cold start times (30–60 min), AEL systems are advised to operate continuously. Another disadvantage of AEL is that the electrolytes are highly corrosive, necessitating frequent maintenance. PEM electrolyzers have faster cold start times and greater flexibility. The minimum load is reported to be 5%, but could reach 0% by 2025 [82]. PEM electrolyzers are largely viewed to have the most potential upside for commercial development and coupling with excess wind or solar PV-based electricity. Solid-oxide electrolysis cells are an emerging electrolyzer technology currently under development.

The European Commission undertook a forecast of technology development for PEM electrolyzers and found three future potential sizes, as summarized in Table 1, with most PEM electrolyzers operating

Table 1
Summary of AEL and PEM technologies [83–87].

	AEL	PEM
Minimum operating capacity [%]	20	5
Pressure output [bar]	0	30
Power consumption [kWh/m^3H_2]	4.5–7	4.5–7.5
CAPEX [$/kW]	900-1500	1400–1800
Lifetime – system [years]	20	20
Lifetime - stack [hours]	80,000	40,000

Table 2
Summary of storage technologies from interviewed companies.

Company	Type	Discharging duration (hr)	Land usage (m^2/MW)	Land usage (m^2/MWh)	Energy capacity (MWh)	Discharging power capacity (MW)	Lifetime (years)	Self-discharge rate (%/day)	Roundtrip efficiency (%)	Response time (s)	Marginal energy capital cost ($/kWh)	Average capital cost ($/kW)	Average capital cost ($/kWh)	Fixed O&M ($/kW-yr)
Hydrostor	Adiabatic CAES	4–24	400-950[e]	50-120[e]	400–19200	100–800	30–50	1	60–70	~180	~80	1500–2500	120–350	17–19
Anonymous A	Flow Battery	8–200	150–200	20–25	0.16–240	0.02–10	20	0.5–0.7	65	~1	45	3808	475	20–50
Anonymous B	Flow Battery	2–12		95–190										
Quidnet	Geomechanical Hydropower	~10			160–3200	160–320	40	0.5	65–75	300–900	5–10	500–1000	50–100	10–20
Energy Vault	Gravity	2–15		~150	50–10000	20–1000	35	0	83–85	~5	~100		200–300	~20
Renewell	Gravity	1–200			0.15–100	25–100	25–50	0	74	~1			50-75[d]	50
HighView	Liquid air	4–24		20–40	10–1000	10–200	30	0.5–1	55[c]	~600	100–200			
Cat Creek[a]	Pumped Hydropower	120–725	11,000	~100	3×10^6	120 per turbine, six turbines in total	100	Evaporation	83	~5		2220	0.05	9.4
Antora	Thermal	10–250	50–100	10–20	5–50000	0.5–200	30	0.5–2	50	~5	5	400–750	10	10
ETES[b]	Thermal	6–48		7	240–1600	30–100	25	1	39	~300	1–2.5		126–154	
Malta	Thermal	8–24	150	15	800–2400	100	30	0.6	53–65	~1	25–30	750	25	

[a] This company has only one project by the time of writing and the data is project specific and is not representative of the technology.
[b] This data is only applicable for powerplant retrofits, not other applications. The MW/MWh should be MW_e/MWh_e to distinguish from the heat power/energy.
[c] This data does not consider heat integration to further increase the efficiency.
[d] The cost considers the payment from the oil and gas companies to remediate inactive wells.
[e] These numbers do not count underground structures.

at 1–5 MW and new electrolyzers expanding up to 20 MW.

3. Comparison in detail

To clarify several terms in Tables 2 and 3, *Land Use/Footprint* refers to the overall system, including support structures. *Roundtrip Efficiency* is the overall efficiency of energy entering and immediately leaving the system such that idle losses are negligible. Idle losses are accounted for under *Daily Self-Discharge Rate* (%/day). Unless otherwise noted, *Average Capital Cost* ($/kWh or $/kW) reflects the total inclusive cost of building a sample system divided by the energy or power of said system, not the costs specific to energy storage or power, which would be better represented by *Marginal Capital Cost* ($/kWh or $/kW). We describe the size of systems by *Energy Capacity* (MWh) and *Power Capacity* (MW). The *Duration Discharge at Rated Discharge Power (h)* is calculated from the ratio of the *Energy Capacity* and *Power Capacity* for a given system, but underrepresents the actual discharge time when the discharge power is less than the rated power. Source values for minimum and maximum *Energy* and *Power Capacity* could be constrained by the technical feasibility and/or economic feasibility if provided by companies.

Variable O&M costs are dominated by system-level electricity prices instead of associated technology costs and thus are not presented.

Tables 2 and 3 introduce a summary of the storage technologies examined in this paper. Table 2 highlights storage technologies from companies that are under development and seeking commercialization opportunities. The data is based on our communication with the companies. The data presented includes important features such as the range of discharge duration to the land required to install new projects. This is a relevant parameter as new plants that are being planned may be sited at locations that previously housed a power plant or some technologies are restricted in terms of the size requirements of a plant. Table 3 summarizes the major characteristics across commercialized or under commercialization long duration storage technologies. The technologies summarized can be broadly categorized into types of compressed air energy storage, flow batteries, gravity storage, innovative hydropower, pumped storage hydropower, and thermal storage. Lithium-ion battery values are given for comparative reference only to provide context. All the data in Table 3 is based on the literature that are also cited in technology introduction sections. Data were selected to be relevant to commercial large-scale storage and were screened to ensure consistency with definition of all the metrics.

3.1. Land footprint

Traditional LDES technologies, as represented by pumped hydropower storage and CAES, are characterized by their geographic limitations and environmental impacts.

Fig. 4 highlights the land use footprint of multiple LDES technologies as a function of energy rating – ranging from several square meters to thousands square kilometers, depending on application and use, and compared with reference values in terms of area and energy needs in California [89].

Having smaller footprints for emerging technologies may inspire new business models (e.g., modular distributed storage) for long-duration energy storage to enter the market. For example, small TPV storage options such as those developed by Antora Energy are likely to support more flexible sizing and siting with smaller minimum footprints. Other storage options, such as small flow batteries could provide back-up power to commercial buildings or residences next to a single-car garage, enabling a distributive capability for this technology.

The siting location of storage technologies also varies depending on physical power plant infrastructure needed to complement installations. The smaller scale of thermal storage comparing with thermal power plants provide a potentially profitable retrofit option where carbon-intensive thermal generation that may be costly to operate can be phased-out by replacing silos and powering turbines with steam from particle thermal storage. These thermal technologies may offer relief to power plant owners who fear operating future stranded assets or could provide employment opportunities for workers trained in operating thermal power plants. Liquid-air energy storage can also utilize waste heat with a similar footprint. Liquid-air overcomes the geographic constraints of conventional compressed air technology, which needs underground caverns.

In addition to retrofits power plants, tower gravity technology can also be deployed near demand centers as the manufacturing and operation is similar to building construction. A place the size of Union Square plaza in San Francisco (~10,000 m^2) could hold a 70 MWh Energy Vault project. The underwater PSH technology seems to fit the size of a farm pond but it has an additional requirement related to water depth. Yet, the modularity of underwater PSH adds flexibility in the location and installed capacity of new projects. For example, it is possible to deploy in larger water bodies such as Lake Tahoe, CA. When comparing technologies, as shown in Fig. 4, one can also identify both the advantages for economies-of-scale with larger energy footprint plants such as PSH or advanced rail storage, and the disadvantages related to limitations in the available land-area for deployment.

The land footprint uniquely describes a less-commonly discussed aspect of the energy transition. Geographic requirements, especially in states or countries with limited land availability and protected natural and cultural territories, present constraints and opportunities for long-duration storage technologies. The co-location flexibility and modularity in arrangements could be an advantage for siting new projects and reducing overall system costs due to land, while simultaneously reducing area-related environmental and social impacts. Alternatively, the footprint graph also presents market entry opportunities at different scales in the power grid, whether in the distribution system, transmission system, or as a replacement/complement to existing generation.

3.2. Equivalent efficiency

Equivalent efficiency also presents a critical feature of LDES technologies, as represented in Fig. 5. The equivalent efficiency is defined as the roundtrip efficiency (RTE) multiplied by the hourly idle losses from storage, as described in Eq. (1), – which demonstrates how storage technology efficiencies change as a function of application from hourly (demand arbitrage) to seasonal applications. Idle losses differ across technologies, but matter for storage options where the duration is unknown (such as charging up gravity storage and waiting for dispatch).

As shown in Fig. 5, Li-ion batteries have almost the highest RTE and relatively low idle losses, but cannot easily decouple energy and power. They also have cooling requirements that can pose challenges in hot environments and reduce the system efficiency. The mechanical based storage technologies (gravity and PSH) have a relatively high RTE and low idle loss and can outcompete Li-ion battery at a seasonal scale. Mechanical based technologies footprint and economies of scale lead them to have large energy ratings. As they can efficiently store a large amount of energy over a year, they become ideal for provision of seasonal storage, resilience and emergency response.

Flow batteries are among the second tier of technologies in terms of RTE, performing well for weeks with significant decline after a month. Geomechanical storage as an innovative hydropower storage option needs underground infrastructure and the equivalent efficiency declines similarly to flow batteries. LAES has similar, although lower, efficiency curve. Considering the deliverable size and footprint, flow batteries, underground storage and LAES both operate at weeks scale but could enter the market in different ways. Flow batteries could start from residential and commercial customers while underground storage and LAES could do so at a much larger scale. Comparing with underground storage, LAES is more flexible in terms of geographic constraints and utilize the heat from thermal power plants or other industrial process.

The thermal and power-to-gas-to-power technologies have the lowest RTE. The low equivalent efficiency curves impose a great

Table 3
Summary of commercially viable long duration storage.

Type	Subtype	Discharging Duration (h)	Response time	Land Usage (m^2/kW)	Land Usage (m^2/kWh)	Energy capacity (MWh)	Discharging power capacity (MW)	Lifetime (years)	Daily self-discharge rate (%/day)	Roundtrip efficiency (%)	Average capital cost ($/kW)	Average capital cost ($/kWh)
Compressed air energy storage	Adiabatic	10–100	3–10 min	15-17[a]	0.27–0.3[a]	10–10000	1–300	20–30	0.5–1	55–75	700–1100	40–90
Compressed air energy storage	Liquid[b]	4–24	5–10 min			10–1000	5–100	20–40		50–85	900–4500	280–580
Flow battery	Vanadium-based flow battery	4–24	milliseconds			0.1–100	0.01–10	5–20	0–1	65–85	600–1650	160–1150
Flow battery	Zinc-based flow battery	4–24	milliseconds			0.1–100	0.01–10	5–20	0.24–33	65–75	700–2700	160–1800
Gravity Storage	Rail-based gravity storage[b]	4–24	seconds	~5	~20	100–20000	10–3000	~40		75–80	~1300	
Gravity Storage	Block-based gravity storage[b]	4–24	seconds		~0.16	4–10000	1–1000	~40		80–85		
Innovative Hydropower	Ground level pumped storage[b]	4–24	seconds-3 minutes			4–2000	1–300			75–85		260–5500
Innovative Hydropower	Underwater mechanical storage[b]	4–24	~1 min	~0.12	~0.03	20–4000	5–1000	5–20		70–75	1850–2500	520–680
Pumped storage hydropower	Pumped storage hydropower	10–100	seconds- 5 min			100–20000	10–3000	25–100	0–0.02	60–85	1800–3400	5–200
Thermal Storage	Concentrated solar power (CSP)[c]	4–24		0.13–2.3[a]	0.03–1.2[a]	0.1–2000	1–300					50–7000
Li-ion Battery[d]		0–4	milliseconds					5–20	0.09–0.36	90–95	1600–2500	300–900

[a] The data are estimated based on Google Earth.
[b] These technologies are in their early stage and these parameters could change significantly depending on the technology advancement.
[c] Concentrated Solar Power (CSP) is generational technology and includes a storage component, but different from other long duration storage technologies shown in the table.
[d] Li-ion is not a long duration energy storage technology.

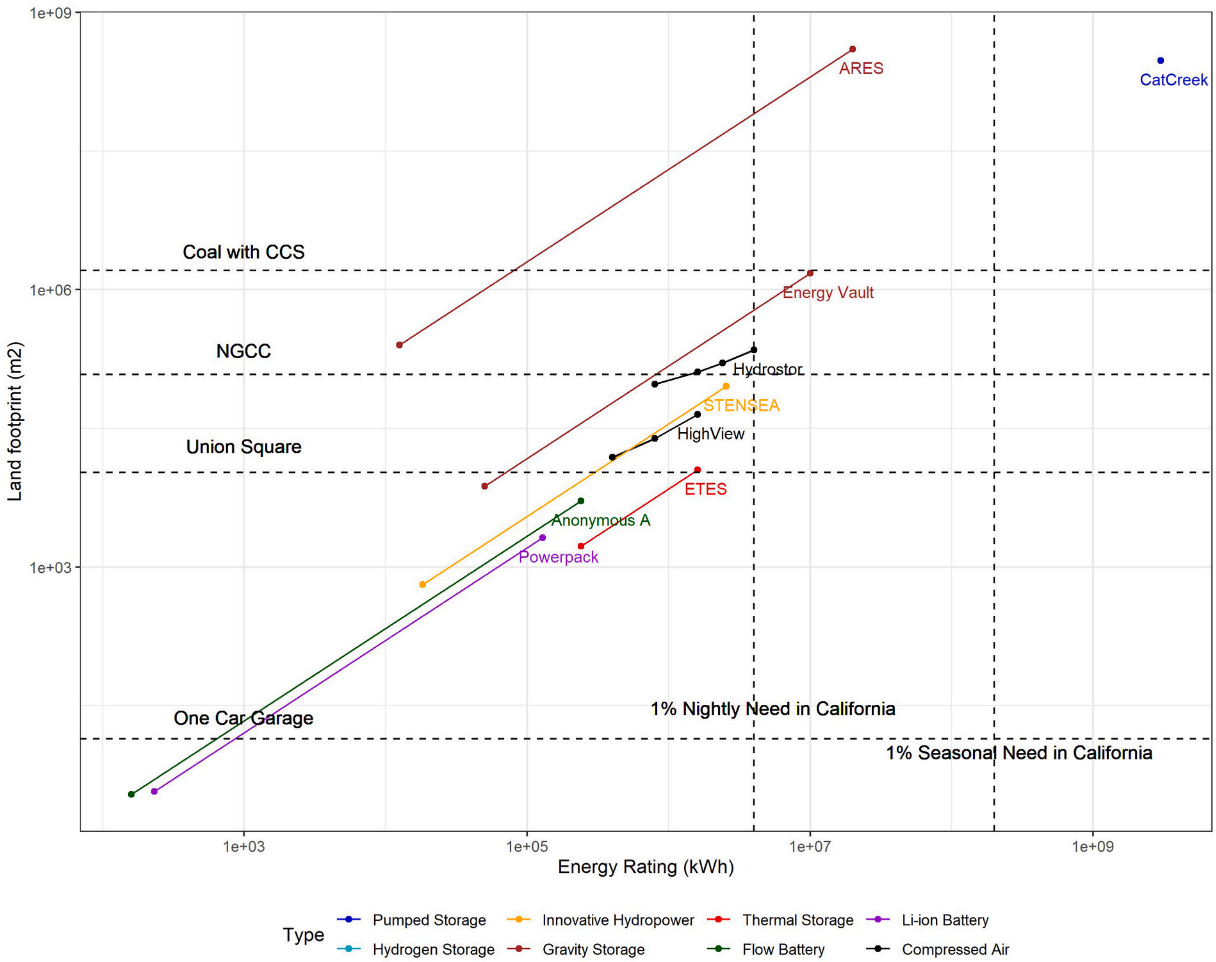

Fig. 4. *Land footprints (m^2) of different technologies (and their related companies) as a function of energy rating (kWh), FB: Flow battery; Li: Lithium-ion battery; PS: Pumped storage hydropower; GR: Gravity storage; IH: Innovative hydropower storage; TS: Thermal Storage The estimated footprints of thermal plants are from Strata Policy* [88]. *Storage demand for California is based on* [89]. *We use Tesla's Powerpack* [90], *a utility battery product to indicate the footprint of Li-ion battery.*

challenge for them to make energy arbitrage, which requires the efficiency higher than the off-peak peak price ratio or the price ratio of charging/discharging. Thus, we would expect them to rely more on revenue from selling the heat or the gas directly and possible ancillary services in the electricity market.

The idle energy loss component of equivalent efficiency for thermal systems strongly depends on the effectiveness and cost of insulation technology, and the issue of heat loss is rarely discussed regarding current CSP systems, as they are typically built for duration times of 10 h or less. Current estimates for most thermal systems give a loss of 3–10% on a weekly basis, depending on scale, with many assuming a default 1% daily rate [73,74]. Theoretically, thermochemical storage would bypass the problem of idle loss entirely, but no projects appear to be commercially deployed.

The loss during storage of hydrogen depends on the storage materials, storage methods, hydrogen carriers, and environmental conditions [91]. Among countless hydrogen storage technologies, we assume the hydrogen is stored in liquid hydrogen in a compressed vessel, because this method allows easy transportation and utilization in other sectors. One drawback is the boil-off rate of 1–5% per day during storage [92]. Despite the high boil-off rate, it may not realistically be a critical problem even for long-term storage because the storage site is usually located near the liquefaction plant that can liquify the boil-off gas at a low cost and inject liquid hydrogen back into the system.

3.3. Average capital cost

The cost of LDES technologies creates a variety of trade-offs and major considerations in addition to the footprint and equivalent efficiency of a candidate technology. For instance, the cost reduction as a function of discharging duration at rated power, calculated via Eq. (2) is illustrated in Fig. 6, and demonstrates that as duration increases, some of the larger-scale and larger-footprint technologies compete more directly on a cost basis with smaller projects and particularly could outcompete Li-ion storage. The sharp decline of the average cost benchmarking with the 4-h system indicates a low marginal energy cost and the decoupling capability between energy rating and power rating, which is a key difference between long and short duration energy storage technologies.

The duration also blurs the differences of their size, either in energy rating or power rating. For example, even if the duration looks the same for a flow battery system and an innovative hydropower system, the flow battery system may be orders of magnitude smaller in the power and energy rating.

When taken together with applications (such as the equivalent efficiency for seasonal or weekly storage) and including information related to the footprint of projects, one can start identifying tradeoffs and opportunities for innovation and market growth in the long duration energy space that might not be intuitive through standalone information only. For example, although flow battery technologies appear to offer capital cost advantages for smaller projects, one can identify future innovations that focus on extending the efficiency for longer durations to

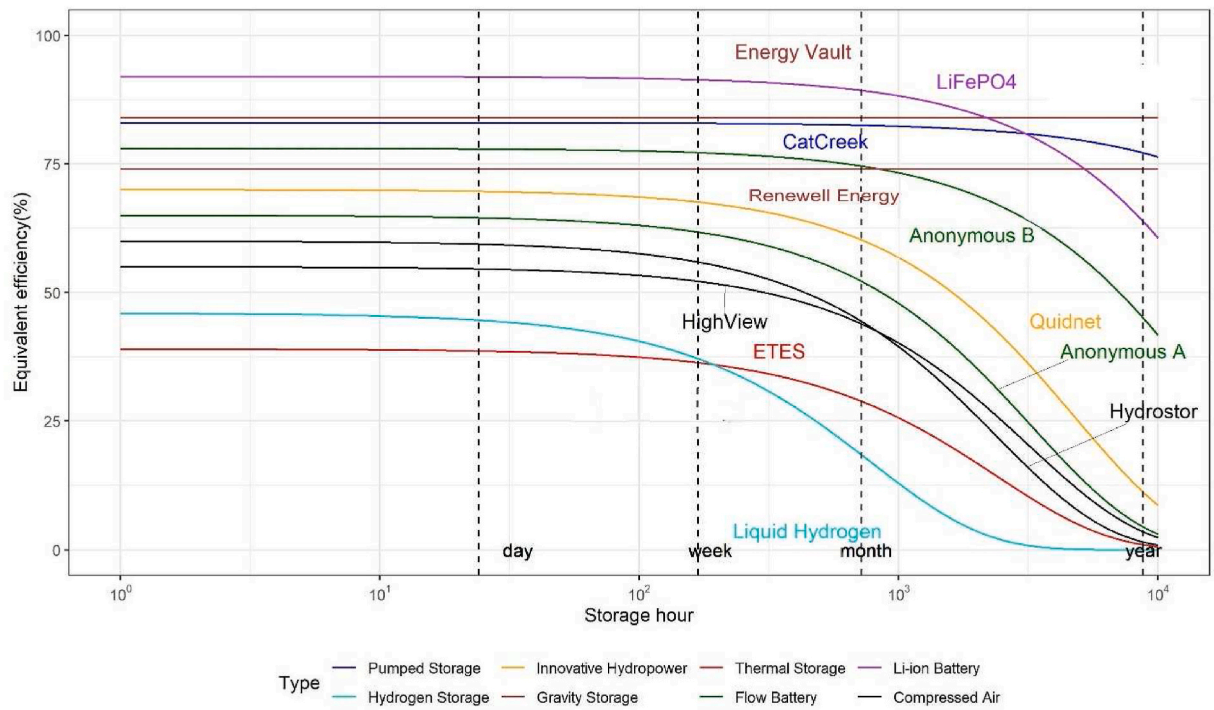

Fig. 5. *Equivalent efficiency of different storage technologies as a function of time. Idle loss of LFP is based on* [38] *and does not include parasitic energy uses that may be highly dependent on operating conditions (*e.g. *air conditioning).*

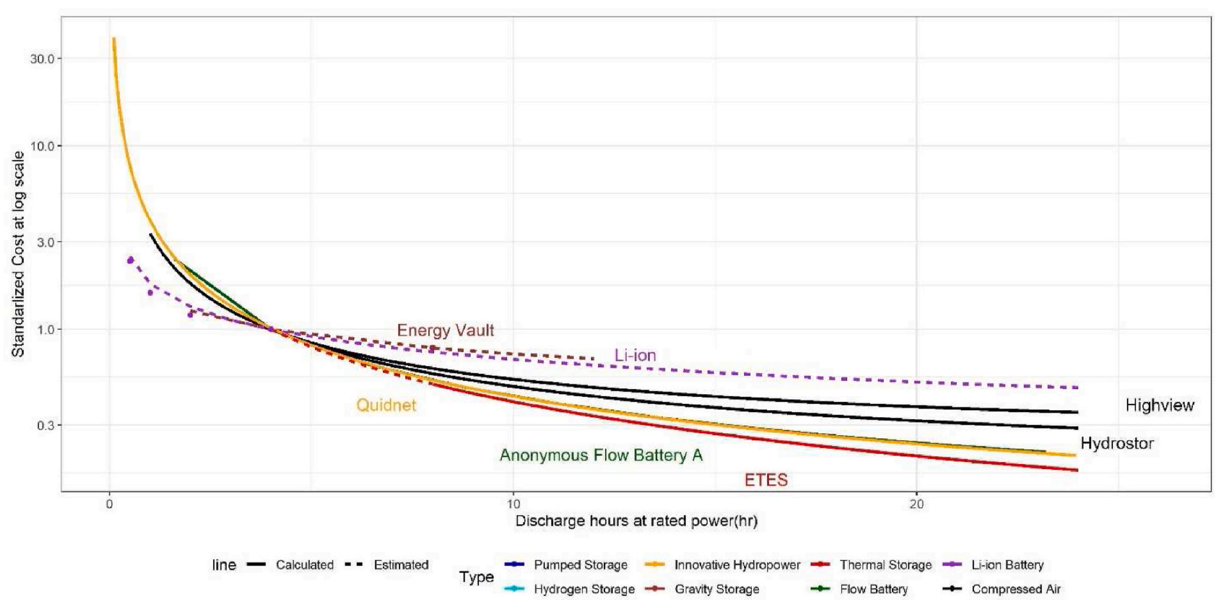

Fig. 6. Standardized average capital cost of different energy storage technologies as a function of duration, or discharge hours at a rated power. A solid line indicates that the system has fixed power and an increasing energy rating and the dash line is the trendline based on limited data points. To protect the cost information of the companies, we did not disclose the power rating but they could be quite different. Thus, the figure should be used to compare the shapes of the curves more than the absolute values of the curves. Energy Vault only has four data points with different energy ratings and power ratings: (1) 300 MWh, 75 MW, 276$/kwh (2) 100 MWh, 25 MW, 290$/kWh, (3) 300 MWh, 37.5 MW, 218$/kWh, (4) 100 MWh, 12.5 MW, 230$/kWh.

make flow batteries more competitive with other long-duration storage technologies. At a larger energy rating, a technology like hydropower storage gradually outcompetes gravity storage like Energy Vault which has advantages in both efficiency and footprint. However, despite the large footprint and geological constraint, hydropower storage project could be much cheaper if an ideal site appears, for example, two reservoirs already exist. Thermal storage and power-to-gas-to-power technology still burden a relatively high capital cost and would be difficult to compete with other long-duration storage technologies, given their land footprint and equivalent efficiency. Acting as an electric storage system may not be their main business model, but participating in the electric market might increase project profitability besides the revenue from selling heat or hydrogen.

4. Conclusion

In this paper, we present various emerging LDES technologies, from conventional PSH and compressed air energy storage technologies, to innovative gravity storage and TPV technologies. The survey with technology developers, in addition to recent literature search provide a review of cost, land footprint, and electric performance of deployed pilots and prototypes of LDES technologies. By comparing their capital cost, deliverable size, land footprint, and equivalent efficiency, we identify possible market entry strategies and innovation paths that may enhance their competitiveness and inform future technology development. As shown in Fig. 7, a qualitative summary of the review, it is challenging for one technology to outperform others in all metrics and to dominate all the markets.

Flow batteries, despite their diverse subtypes, have advantages in the minimum deliverable size, energy footprint and cost, making them suitable for the residential and commercial sectors, but their high idle loss constrains their charge-discharge cycle to several weeks. Improvements in their idle loss rate or round-trip efficiency can increase their competitiveness with other technologies in the monthly storage market. Vertical designed gravity storage technology, like Energy Vault, with a medium land footprint to be placed near demand centers, could be cost-competitive at a larger energy rating and longer discharge duration to support city level storage demand, acting as back-up energy for resilience purpose, or even for seasonal storage, due to their minimal idle loss. Some vertical gravity storage technologies can also be integrated with building and distributed deployed. Liquid air energy storage and innovative CAES-hydro combined technologies like Hydrostor share similar land footprint and deliverable size with Energy Vault, and thus could also support regional level inter-day storage demand but not seasonal due to idle loss. In the similar inter-day storage space, we also find conventional CAES and underground hydropower storage technology like Quidnet categorized as such due to their equivalent efficiency. These technologies are constrained by underground infrastructure, but they also have opportunities to achieve low cost with existing underground infrastructure. To economically meet an even larger energy storage demand in a single project, PSH dominates where low-idle losses can support seasonal needs. The thermal storage and power-to-gas technologies are not currently competitive in terms of equivalent efficiency, nor capital cost. Thus, we would not expect them only to rely on revenue from the electricity market nor to start from a greenfield project. Thermal storage technologies could enter by retrofitting thermal plants to revitalize stranded assets and sell both low-carbon heat and electricity. Power-to-gas projects should locate where pipeline and other gas-related infrastructure are already in place, because they could sell both electricity and gas. Cross sectoral innovations will play a large role in the market entry strategy for these technologies. For instance, thermal storage may appear to have lower efficiencies than other technologies, but may be critical in decarbonizing heat and other industrial processes where electricity may not be as cost-effective. TPV based storage system like Antora also has the potential to be distributed deployed with its small footprint. Additionally, liquid hydrogen, which may perform poorly on an equivalent efficiency basis on current storage technology, has multiple applications that warrant further research and development as part of a wider decarbonization strategy. Other hydrogen utilization and storage technologies may have better performance in equivalent efficiency and related applications. It is promising to view a healthy competition across emerging hydrogen technologies where the number of applications could increase in the future.

LDES technologies will likely play a critical role in decarbonizing the power grid if technologies develop further. Some LDES options are on the grid and commercialized today – but further improvements in efficiency and land-usage could facilitate greater system-level deployment. Further research, development, and demonstration projects that could bring costs further down from their current state would reduce overall energy system costs of decarbonization and help in the transition to clean, low-carbon energy across the world.

Credit author statement

Rui Shan: Conceptualization, Methodology, Data curation, Writing – original draft, Writing – review & editing, Jeremiah Reagan: Methodology, Data curation, Writing – original draft, Sergio Castellanos: Data curation, Writing – review & editing, Sarah Kurtz: Conceptualization, Methodology, Data curation, Writing – review & editing, Supervision, Noah Kittner: Conceptualization, Methodology, Data curation, Writing – original draft, Writing – review & editing, Supervision.

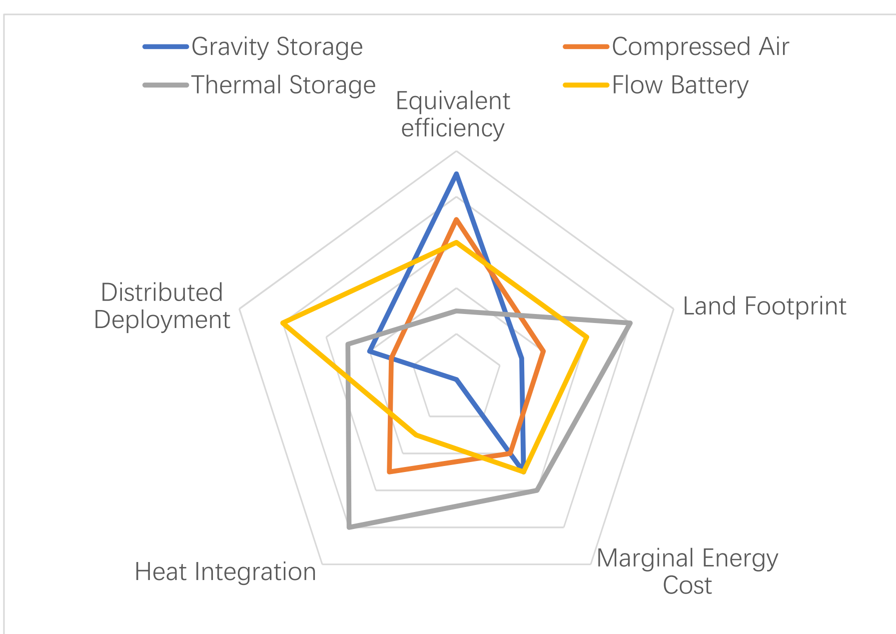

Fig. 7. Qualitative summary of different technologies.

Legal notice

This document was prepared as a result of work sponsored by the California Energy Commission. It does not necessarily represent the views of the Energy Commission, its employees, or the State of California. The Energy Commission, the State of California, its employees, contractors, and subcontractors make no warranty, express or implied, and assume no legal liability for the information in this document; nor does any party represent that the use of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the Energy Commission nor has the Energy Commission passed upon the accuracy of the information in this report.

Data and code availability statement

The data and codes that support the findings of this study are available from the corresponding author upon reasonable requests.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgement

The authors would like to thank the California Energy Commission for funding this work under Contract number EPC-19-060. We thank Julia Prochnik of the Long Duration Energy Storage Association of California for connections to companies. Rui Shan also thanks the Weiss Urban Livability Fellowship at University of Norh Carolina at Chapel Hill.

References

[1] Masson-Delmotte V, Zhai P, Pörtner H-O, Roberts D, Skea J, Shukla PR, et al. Global warming of 1.5 °C: an IPCC special report on the impacts of global warming of 1.5° C above pre-industrial levels and related global greenhouse gas emission pathways. In: The context of strengthening the global response to the threat of climate change. Switzerland: World Meteorological Organization Geneva; 2018.
[2] Edenhofer O, Pichs-Madruga R, Sokona Y, Seyboth K, Matschoss P, Kadner S, et al. Summary for policymakers. In: IPCC special report on renewable energy sources and climate change mitigation. Cambridge, United Kingdom and New York, NY, USA.; 2011.
[3] Few S, Schmidt O, Gambhir A. Electrical energy storage for mitigating climate change. Grantham Institute-Climate Change and the Environment; 2016.
[4] De Sisternes FJ, Jenkins JD, Botterud A. The value of energy storage in decarbonizing the electricity sector. Appl Energy 2016;175:368–79.
[5] Balducci PJ, Alam MJE, Hardy TD, Wu D. Assigning value to energy storage systems at multiple points in an electrical grid. Energy Environ Sci 2018;11: 1926–44. https://doi.org/10.1039/C8EE00569A.
[6] Albertus P, Manser JS, Litzelman S. Long-duration electricity storage applications, economics, and technologies. Joule 2020;4:21–32.
[7] Dowling JA, Rinaldi KZ, Ruggles TH, Davis SJ, Yuan M, Tong F, et al. Role of long-duration energy storage in variable renewable electricity systems. Joule 2020;4: 1907–28.
[8] Blanco H, Faaij A. A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage. Renew Sustain Energy Rev 2018;81:1049–86.
[9] Groppi D, Pfeifer A, Garcia DA, Krajačić G, Duić N. A review on energy storage and demand side management solutions in smart energy islands. Renew Sustain Energy Rev 2021;135:110183. https://doi.org/10.1016/J.RSER.2020.110183.
[10] 2019-2020 electric resource portfolios to inform integrated resource plans and transmission planning. California Public Utilities Commission; 2020.
[11] Mongird K, Viswanathan V, Alam J, Vartanian C, Sprenkle V, Baxter R. Grid energy storage technology cost and performance assessment, vol. 2020. Energy; 2020, 2020.
[12] Aneke M, Wang M. Energy storage technologies and real life applications–A state of the art review. Appl Energy 2016;179:350–77.
[13] Hittinger E, Ciez RE. Modeling costs and benefits of energy storage systems. Annu Rev Environ Resour 2020;45:445–69.
[14] Koohi-Fayegh S, Rosen MA. A review of energy storage types, applications and recent developments. J Energy Storage 2020;27:101047.
[15] Beuse M, Steffen B, Schmidt TS. Projecting the competition between energy-storage technologies in the electricity sector. Joule 2020;4:2162–84.
[16] Schmidt O, Melchior S, Hawkes A, Staffell I. Projecting the future levelized cost of electricity storage technologies. Joule 2019;3:81–100.
[17] Kittner N, Castellanos S, Hidalgo-Gonzalez P, Kammen DM, Kurtz S. Cross-sector storage and modeling needed for deep decarbonization. Joule 2021;5:2529–34. https://doi.org/10.1016/j.joule.2021.09.003.
[18] Sepulveda NA, Jenkins JD, Edington A, Mallapragada DS, Lester RK. The design space for long-duration energy storage in decarbonized power systems. Nat Energy 2021:1–11.
[19] Ogland-Hand JD, Bielicki JM, Adams BM, Nelson ES, Buscheck TA, Saar MO, et al. The value of CO2-Bulk energy storage with wind in transmission-constrained electric power systems. Energy Convers Manag 2021;228:113548. https://doi.org/10.1016/J.ENCONMAN.2020.113548.
[20] Blanco H, Faaij A. A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage. Renew Sustain Energy Rev 2018;81:1049–86. https://doi.org/10.1016/J.RSER.2017.07.062.
[21] Li W, Klemeš JJ, Wang Q, Zeng M. Salt hydrate–based gas-solid thermochemical energy storage: current progress, challenges, and perspectives. Renew Sustain Energy Rev 2022;154:111846. https://doi.org/10.1016/J.RSER.2021.111846.
[22] Yu X, Manthiram A. Sustainable battery materials for next-generation electrical energy storage. Advanced Energy and Sustainability Research 2021;2:2000102. https://doi.org/10.1002/AESR.202000102.
[23] May GJ, Davidson A, Monahov B. Lead batteries for utility energy storage: a review. J Energy Storage 2018;15:145–57. https://doi.org/10.1016/J.EST.2017.11.008.
[24] Gyuk I. DOE global energy storage Database. Albuquerque, NM (United States): Sandia National Lab.(SNL-NM); 2021.
[25] Fu R, Remo TW, Margolis RM. U.S. Utility-scale photovoltaics-plus-energy storage system costs benchmark. Golden, CO (United States). 2018. https://doi.org/10.2172/1483474. 2018.
[26] Hunter CA, Penev MM, Reznicek EP, Eichman J, Rustagi N, Baldwin SF. Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids. Joule 2021;5: 2077–101. https://doi.org/10.1016/J.JOULE.2021.06.018.
[27] Uria Martinez R, Johnson M, Shan R. US hydropower market report (January 2021 edition). Oak Ridge, TN (United States): Oak Ridge National Lab.(ORNL); 2021.
[28] Hunt JD, Byers E, Wada Y, Parkinson S, Gernaat DEHJ, Langan S, et al. Global resource potential of seasonal pumped hydropower storage for energy and water storage. Nat Commun 2020;11:1–8.
[29] Stocks M, Stocks R, Lu B, Cheng C, Blakers A. Global Atlas of closed-loop pumped hydro energy storage. Joule 2021;5:270–84.
[30] IRENA. Innovation landscape brief: innovative operation of pumped hydropower storage. Abu Dhabi. 2020.
[31] Mongird K, Viswanathan VV, Balducci PJ, Alam MJE, Fotedar V, Koritarov VS, et al. Energy storage technology and cost characterization report. Richland, WA (United States): Pacific Northwest National Lab.(PNNL); 2019.
[32] Giovinetto A, Eller A. Comparing the costs of long duration energy storage technologies. National Grid Ventures and Navigant Research See Www Slenergystorage Com/Documents/20190626_Long_ Duration% 20Storage_Costs Pdf 2019.
[33] Klumpp F. Comparison of pumped hydro, hydrogen storage and compressed air energy storage for integrating high shares of renewable energies—potential, cost-comparison and ranking. J Energy Storage 2016;8:119–28.
[34] Krishan O, Suhag S. An updated review of energy storage systems: classification and applications in distributed generation power systems incorporating renewable energy resources. Int J Energy Res 2019;43:6171–210.
[35] Jülch V. Comparison of electricity storage options using levelized cost of storage (LCOS) method. Appl Energy 2016;183:1594–606.
[36] Hunt JD, Zakeri B, Lopes R, Barbosa PSF, Nascimento A, de Castro NJ, et al. Existing and new arrangements of pumped-hydro storage plants. Renew Sustain Energy Rev 2020;129:109914.
[37] Argyrou MC, Christodoulides P, Kalogirou SA. Energy storage for electricity generation and related processes: technologies appraisal and grid scale applications. Renew Sustain Energy Rev 2018;94:804–21.
[38] Ralon P, Taylor M, Ilas A, Diaz-Bone H, Kairies K. Electricity storage and renewables: costs and markets to 2030. Abu Dhabi, UAE: International Renewable Energy Agency; 2017.
[39] Yang C-J, Jackson RB. Opportunities and barriers to pumped-hydro energy storage in the United States. Renew Sustain Energy Rev 2011;15:839–44.
[40] Slocum AH, Fennell GE, Dundar G, Hodder BG, Meredith JDC, Sager MA. Ocean renewable energy storage (ORES) system: analysis of an undersea energy storage concept. Proc IEEE 2013;101:906–24.
[41] Puchta M, Bard J, Dick C, Hau D, Krautkremer B, Thalemann F, et al. Development and testing of a novel offshore pumped storage concept for storing energy at sea−Stensea. J Energy Storage 2017;14:271–5.
[42] Hahn H, Hau D, Dick C, Puchta M. Techno-economic assessment of a subsea energy storage technology for power balancing services. Energy 2017;133:121–7.
[43] Hadjerioua B, Eldredge T, Medina H, DeNeale S. Hydrodynamic and structural response modeling of a prototype floating membrane reservoir system for pumped storage hydropower. J Hydraul Eng 2019;145:4019032.
[44] Witt A, Hadjerioua B, Uría-Martínez R, Bishop Jr NA. Evaluation of the feasibility and viability of modular pumped storage hydro (m-PSH) in the United States. ORNL/TM-2015/559. Oak Ridge, Tennessee: Oak Ridge National Laboratory; 2015.
[45] Madlener R, Specht JM. An exploratory economic analysis of underground pumped-storage hydro power plants in abandoned deep coal mines. Energies 2020; 13:5634.

[46] Menéndez J, Fernández-Oro JM, Galdo M, Loredo J. Efficiency analysis of underground pumped storage hydropower plants. J Energy Storage 2020;28:101234.
[47] Pujades E, Orban P, Bodeux S, Archambeau P, Erpicum S, Dassargues A. Underground pumped storage hydropower plants using open pit mines: how do groundwater exchanges influence the efficiency? Appl Energy 2017;190:135–46.
[48] Quidnet Energy. Quidnet energy - about us. 2020.
[49] Wang H, Wang L, Wang X, Yao E. A novel pumped hydro combined with compressed air energy storage system. Energies 2013;6:1554–67.
[50] Odukomaiya A, Abu-Heiba A, Graham S, Momen AM. Experimental and analytical evaluation of a hydro-pneumatic compressed-air ground-level integrated diverse energy storage (GLIDES) system. Appl Energy 2018;221:75–85.
[51] Kassaee S, Abu-Heiba A, Ally MR, Mench MM, Liu X, Odukomaiya A, et al. PART 1-techno-economic analysis of a grid scale ground-level integrated diverse energy storage (GLIDES) technology. J Energy Storage 2019;25:100792.
[52] 'Potentially the worst drought in 1,200 years': scientists on the scorching US heatwave | Climate crisis in the American west | the Guardian n.d. https://www.theguardian.com/us-news/2021/jun/18/us-heatwave-west-climate-crisis-drought. [Accessed 23 June 2021].
[53] Gravitricity. Fast, long-life energy storage - Gravity energy storage system | Gravitricity technology. https://gravitricity.com/technology/. [Accessed 12 March 2021].
[54] Fyke A. The fall and rise of gravity storage technologies. Joule 2019;3:625–30.
[55] ARES., ARES. Nevada project. ARES; 2019. https://aresnorthamerica.com/nevada-project/. [Accessed 12 June 2021].
[56] Gravity Power Inc. Technology - gravity power energy storage. Official Website; 2017. http://www.gravitypower.net/technology-gravity-power-energy-storage/. [Accessed 12 March 2021].
[57] Energozapas. News-Energozapas. http://energozapas.com/#decision. [Accessed 16 March 2021].
[58] Cava F, Kelly J, Peitzke W, Brown M, Sullivan S. Advanced rail energy storage: green energy storage for green energy. Storing Energy, Elsevier; 2016. p. 69–86.
[59] Moore SK. The Ups and Downs of Gravity Energy Storage: startups are pioneering a radical new alternative to batteries for grid storage. IEEE Spectrum 2020;58:38–9.
[60] Berrada A, Loudiyi K, Zorkani I. Sizing and economic analysis of gravity storage. J Renew Sustain Energy 2016;8:24101.
[61] Schmidt O. Levelized cost of storage gravity storage. 2018.
[62] Berrada A, Loudiyi K, Zorkani I. System design and economic performance of gravity energy storage. J Clean Prod 2017;156:317–26.
[63] Geological Survey U. Mineral commodity summaries. 2021 [n.d].
[64] Hydrostor Inc. Projects – Hydrostor. Hydrostor Inc; 2021.
[65] Budt M, Wolf D, Span R, Yan J. A review on compressed air energy storage: basic principles, past milestones and recent developments. Appl Energy 2016;170:250–68.
[66] Compressed air storage to be more than just hot air in Israel – pv magazine International. n.d. https://www.pv-magazine.com/2021/01/26/compressed-air-storage-to-be-more-than-just-hot-air-in-israel/. [Accessed 4 July 2021].
[67] Willuhn M. Compressed air storage to be more than just hot air in Israel. PV Magazine; 2021.
[68] Power Highview. Plants | Highview power. Highview Power; 2021. https://highviewpower.com/plants/.
[69] Spain may host 2 GWh of liquid air storage – pv magazine International n.d. https://www.pv-magazine.com/2021/05/20/spain-may-host-2-gwh-of-liquid-air-storage/. [Accessed 23 June 2021].
[70] Wang J, Lu K, Ma L, Wang J, Dooner M, Miao S, et al. Overview of compressed air energy storage and technology development. Energies 2017;10:991.
[71] Aquino T, Zuelch C, Koss C. Energy storage technology assessment-prepared for public service company of New Mexico. HDR, Revision C Brentwood, TN, USA. Tech Rep 2017. https://www.pnm.com/documents/396023/1506047/2017+-+HDR+10-30-17+PNM+Energy+Storage+Report.pdf/a2b7ca65-e1ba-92c8-308a-9a8391a87331.
[72] Sarbu I, Sebarchievici C. A comprehensive review of thermal energy storage. Sustainability 2018;10:191.
[73] Smallbone A, Jülch V, Wardle R, Roskilly AP. Levelised cost of storage for pumped heat energy storage in comparison with other energy storage technologies. Energy Convers Manag 2017;152:221–8.
[74] Malta Inc. n.d. https://www.maltainc.com/. [Accessed 23 June 2021].
[75] Huskinson B, Marshak MP, Suh C, Er S, Gerhardt MR, Galvin CJ, et al. A metal-free organic–inorganic aqueous flow battery. Nature 2014;505:195–8.
[76] Barnhart CJ, Benson SM. On the importance of reducing the energetic and material demands of electrical energy storage. Energy Environ Sci 2013;6:1083–92.
[77] Divya KC, Østergaard J. Battery energy storage technology for power systems—an overview. Elec Power Syst Res 2009;79:511–20.
[78] Gielen D, Taibi E, Miranda R. Hydrogen: a renewable energy perspective. International Renewable Energy Agency (IRENA); 2019.
[79] Zhang X, Bauer C, Mutel CL, Volkart K. Life Cycle Assessment of Power-to-Gas: approaches, system variations and their environmental implications. Appl Energy 2017;190:326–38.
[80] Vora SD, Jesionowski G, Williams MC. Overview of U.S. Department of energy office of fossil energy's solid oxide fuel cell program for FY2019. ECS Trans 2019;91:27–39. https://doi.org/10.1149/09101.0027ecst.
[81] Bailera M, Lisbona P, Romeo LM, Espatolero S. Power to Gas projects review: lab, pilot and demo plants for storing renewable energy and CO2. Renew Sustain Energy Rev 2017;69:292–312.
[82] Cell F, Undertaking HJ. Study on early business cases for H2 in energy storage and more broadly power to H2 applications. 2017.
[83] Götz M, Lefebvre J, Mörs F, Koch AM, Graf F, Bajohr S, et al. Renewable Power-to-Gas: a technological and economic review. Renew Energy 2016;85:1371–90.
[84] Schiebahn S, Grube T, Robinius M, Tietze V, Kumar B, Stolten D. Power to gas: technological overview, systems analysis and economic assessment for a case study in Germany. Int J Hydrogen Energy 2015;40:4285–94.
[85] Ruf Y, Baum M, Zorn T, Menzel A, Rehberger J. Fuel cells and hydrogen 2 joint undertaking [n.d].
[86] Siemens. Siemens Sylizer 300 2019.
[87] Scolaro M, Kittner N. Optimizing hybrid offshore wind farms for cost-competitive hydrogen production in Germany. Int J Hydrogen Energy 2022;47(10):6478–93. https://doi.org/10.1016/j.ijhydene.2021.12.062.
[88] Stevens L, Anderson B, Cowan C, Colton K, Johnson D. The footprint of energy: land use of US Electricity production. Logan, UT, USA: STRATA; 2017.
[89] Abido M, Shiraishi K, Sanchez Perez PA, Jones R, Mahmud Z, Castellanos S, et al. Seasonal challenges for a zero-carbon grid in California. 2021.
[90] Powerpack - commercial & utility energy storage solutions | Tesla n.d. https://www.tesla.com/powerpack. [Accessed 30 June 2021].
[91] Andersson J, Grönkvist S. Large-scale storage of hydrogen. Int J Hydrogen Energy 2019;44:11901–19. https://doi.org/10.1016/j.ijhydene.2019.03.063.
[92] Derking H, van der Togt L, Keezer M, Bv C. Liquid hydrogen storage: Status and future perspectives. [n.d].