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GRID-SCALE AND DISTRIBUTED ENERGY STORAGE, 2010–2026: A COMPREHENSIVE REVIEW OF TECHNOLOGIES, MARKETS AND POLICY FRAMEWORKS

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Abstract
Energy storage is now a central enabler of electricity system decarbonisation. It addresses the intermittency of solar and wind generation and provides the flexibility services that high-renewable power systems require. Scope and method: This study is a state-of-the-art review covering the period 2010–2026. It synthesises peer-reviewed literature and verified industry data across electrochemical, mechanical, chemical and thermal storage pathways, their economics, grid applications and policy frameworks, with a new dedicated treatment of the African context. Principal findings: Lithium-ion battery pack prices fell to a record low of USD 108/kWh in 2025, 93% below 2010 levels, while stationary storage packs reached USD 70/kWh [1, 2]. Global annual battery storage additions reached 108 GW in 2025, about 40% above 2024, and cumulative global storage capacity approached 460 GW [3, 4]. Turnkey utility-scale system costs fell about 40% between 2023 and 2024, but with pronounced regional divergence: approximately USD 101/kWh in China, USD 236/kWh in the United States and USD 275/kWh in Europe. Levelised cost of storage analysis shows lithium-ion dominates durations below 4–6 h, while pumped hydro, compressed air and hydrogen pathways are competitive at longer durations. The January 2025 fire at the Moss Landing facility in California, which damaged about 55% of some 100,000 battery modules, shows that safety engineering and standards enforcement must scale with deployment [5]. Implications: The study concludes that storage is cost-competitive for short-duration flexibility, that long-duration and seasonal storage remain the principal technology gap, and that weak-grid and diesel-displacement applications represent the dominant near-term commercial case for storage in sub-Saharan Africa. Actionable recommendations are offered for policymakers, industry stakeholders and researchers.

Keywords
energy storage; grid integration; levelised cost of storage; energy policy; renewable energy

1. INTRODUCTION

The global energy landscape is undergoing a profound transformation. The imperative is to decarbonise energy systems and mitigate climate change. Global renewable power capacity additions reached a record 582 GW in 2024, of which solar photovoltaics contributed 452 GW and wind 114 GW [6]. The variable nature of these sources presents significant challenges for grid stability and reliability. Energy storage solutions that balance supply and demand across multiple timescales are therefore required [7].

Energy storage has evolved from niche applications to mainstream grid infrastructure. Cumulative global battery storage capacity stood at about 86 GW in 2023 and more than tripled to about 263 GW by the end of 2025 [4, 3]. Including pumped hydroelectric storage of approximately 193 GW, total installed energy storage capacity approached 460 GW by the end of 2025 [6]. Lithium-ion battery pack prices declined by about 93% between 2010 and 2025, from roughly USD 1,191/kWh to USD 108/kWh in nominal terms [2]. Pack prices for stationary storage specifically reached USD 70/kWh in 2025, making stationary storage the lowest-priced segment for the first time [2]. Annual investment in battery storage exceeded USD 50 billion by 2024 [8]. The cost trajectory of lithium-ion packs over the review period is shown in Figure 1.

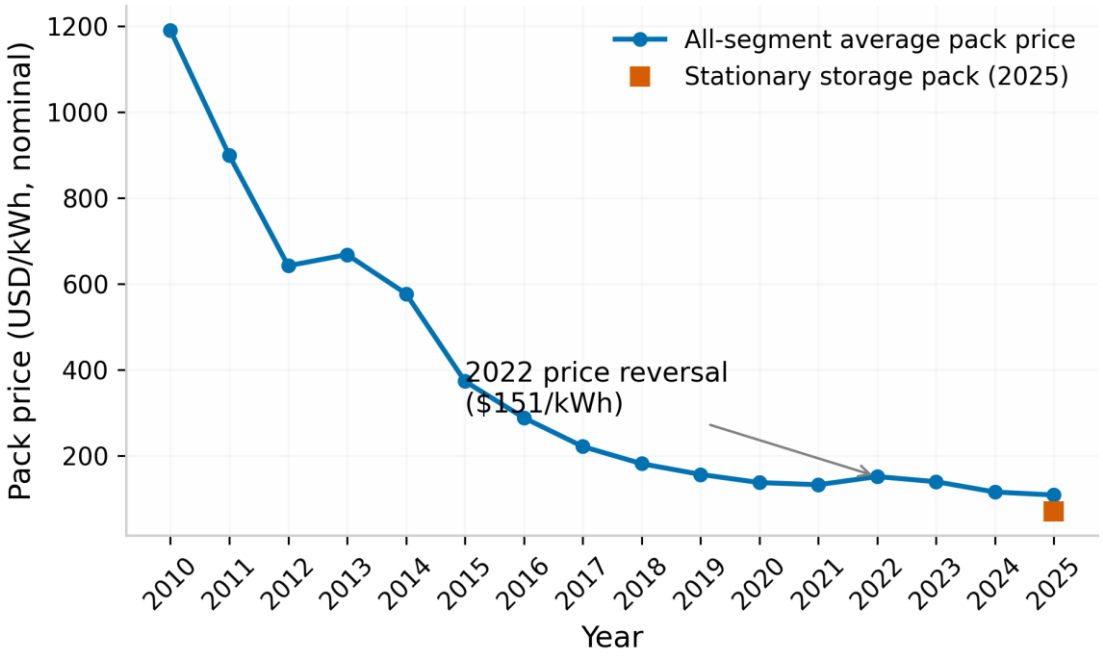


Figure 1: Lithium-ion battery pack price decline, 2010–2025 (nominal USD/kWh). The 2022 increase to USD 151/kWh, driven by lithium carbonate price rises, is a notable departure from the learning curve. Data source: BloombergNEF annual battery price surveys [1, 2].

The role of energy storage extends beyond energy arbitrage. Storage systems provide frequency regulation, voltage support and reserves that are essential for grid stability [9]. Storage enables higher renewable penetration by shifting generation from periods of excess supply to periods of high demand. This reduces curtailment and improves asset utilisation [10]. The technology landscape is diverse. It spans electrochemical systems, mechanical systems, chemical systems and thermal systems. Each technology offers distinct characteristics in energy density, power density, cycle life, response time and cost structure. These characteristics determine suitability for different applications [11]. The cumulative global deployment of the main technologies over 2020–2025 is shown in Figure 2.

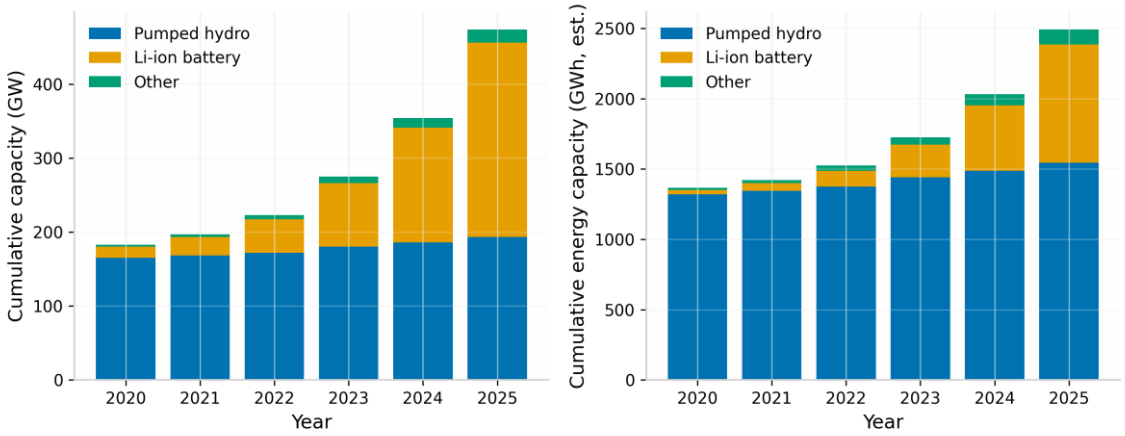


Figure 2: Cumulative global installed energy storage capacity by technology, 2020–2025, in (a) power (GW) and (b) energy (GWh, estimated from typical durations). Pumped hydro values are cumulative installed capacity; battery values are cumulative additions. Data sources: IRENA [6]; Ember [4]; IEA [3].

Despite this progress, challenges remain. Material constraints for lithium and cobalt raise concerns about supply chain sustainability [12]. Long-duration storage for multi-day and seasonal imbalances remains largely unmet by current technologies [13]. Market frameworks in many jurisdictions fail to compensate storage for the full range of services it provides [14].

Several comprehensive storage reviews have appeared since 2020. Most are limited to a single technology family or to strong-grid applications in high-income markets. This review fills three gaps. First, it integrates quantitative engineering analysis, including levelised cost of storage and process parameters, across all major

technology families. Second, it updates the evidence base through 2025–2026, a period of unusually rapid change in costs and deployment. Third, it provides a dedicated treatment of energy storage in the African context, covering weak grids, diesel displacement, mini-grids, high-temperature operation and regional mineral value chains.

Energy storage plays a multifaceted role in enabling the transition to sustainable energy systems, addressing challenges at multiple scales and timescales. At the generation level, storage smooths the output of variable renewable sources, reducing ramp rates and providing firm capacity [15].

Substantive treatment of grid services, renewable integration and behind-the-meter applications is consolidated in Section 5 to avoid duplication.

This study pursues five objectives: to assess energy storage technologies across the main technological pathways, their performance metrics and maturity levels; to analyse cost trends, levelised costs and market developments in energy storage; to evaluate the grid services and applications that energy storage provides; to examine the policy and regulatory frameworks that govern storage deployment; to identify the principal challenges, gaps and research needs in the field.

The scope encompasses storage technologies relevant to grid-scale and distributed applications over 2010–2026. Electrochemical storage covers lithium-ion, sodium-ion, lead-acid, solid-state, metal-air, flow batteries and supercapacitors. Mechanical storage covers pumped hydro, compressed air, gravity and flywheel systems. Chemical storage covers hydrogen, synthetic fuels and ammonia. Thermal storage covers sensible, latent and thermochemical systems. Electric vehicles are treated only where they intersect with the grid, through second-life batteries and vehicle-to-grid integration. Geographically, the review covers China, the United States and Europe, and adds a dedicated treatment of sub-Saharan Africa. The review has three limitations. It relies on secondary cost data, which carries reporting-lag uncertainty. Grey literature such as industry surveys is used where peer-reviewed data are unavailable, and this is indicated at each use. Emerging laboratory-scale technologies without commercial demonstration are excluded.

This is a state-of-the-art review, not a full systematic review, and the language of systematic method is therefore not claimed. The review followed a structured protocol informed by PRISMA principles. Major academic databases (Web of Science, Scopus and IEEE Xplore) were searched using the strings "energy storage" AND ("battery" OR "pumped hydro" OR "compressed air" OR "hydrogen" OR "thermal storage") AND ("grid integration" OR "levelised cost" OR "energy policy"). The final search was executed in the period covered by this review. The initial search yielded over 4,000 records. Records were included if they reported original technical, economic or policy findings on grid-scale or distributed storage, were published in English, and passed a quality appraisal based on methodological transparency and data traceability. Records were excluded if they addressed only consumer electronics, duplicated data, or lacked verifiable methods. Screening by the four authors produced 207 items retained for detailed analysis, of which the sources cited herein represent the core evidence base. The screening funnel was: 4,000 records identified, 812 after title and abstract screening, 207 after full-text eligibility assessment, and 64 core sources cited. Industry and agency reports (IEA, IRENA, BloombergNEF, Wood Mackenzie, Ember, US EIA) supplemented the academic literature for 2024–2026 data. No AI or automated screening tools were used at any stage.

2. ELECTROCHEMICAL ENERGY STORAGE

2.1 Lithium-ion Battery Technologies

Lithium-ion batteries dominate new storage deployment. Lithium iron phosphate (LFP) chemistry alone accounted for more than 90% of annual stationary storage additions in 2025 [16]. The success of the technology stems from high energy density, long cycle life, rapid response and rapidly declining costs. Commercial cells achieve gravimetric energy densities of 150–280 Wh/kg for nickel-manganese-cobalt (NMC) chemistries and 160–205 Wh/kg for LFP, with volumetric values of 400–700 Wh/L and 350–450 Wh/L respectively at cell level [17, 18]. Pack-level values are typically 20–30% lower.

Each chemistry offers distinct trade-offs. NMC offers the highest energy density but relies on cobalt, which raises supply chain and ethical concerns [12]. LFP offers superior cycle life and thermal stability at lower cost, and has become the default chemistry for stationary storage [18, 19]. Degradation behaviour differs by chemistry and duty. Degradation has two components: calendar ageing, which proceeds with time and is driven by state of charge and temperature, and cycle ageing, which proceeds with throughput and is driven by depth of discharge, C-rate and temperature. Both manifest as capacity fade and resistance growth, tracked through state of health. Degradation is a central economic driver because it determines warranty terms and the augmentation strategy required to hold rated capacity over project life [18].

Manufacturing scale-up has been extraordinary. Global cell production capacity exceeded 2,000 GWh by 2023 and Chinese stationary-storage cell capacity alone was estimated at 557 GWh in 2025, roughly double global demand in that segment [16, 2]. This overcapacity is a principal driver of current price competition. Innovation continues. Silicon-blend anodes raise energy density but introduce cycle-life challenges [20]. Solid-state electrolytes promise safety and energy-density gains, and pilot production lines operated by

several manufacturers between 2024 and 2026 have moved the technology towards commercialisation in the late 2020s [21, 22].

2.2 Alternative Battery Chemistries and Supercapacitors

Sodium-ion batteries avoid lithium supply constraints and use abundant raw materials. They achieve cell-level energy densities of 100–160 Wh/kg and can leverage existing lithium-ion manufacturing lines [23, 24]. Commercialisation has advanced rapidly. CATL and HyperStrong signed a three-year supply partnership totalling 60 GWh of sodium-ion batteries in 2025, and further supply agreements for stationary storage deployment between 2027 and 2030 have been announced [16]. Sodium-ion remains more expensive than lithium-ion today because of limited scale, but cost parity is plausible as volumes grow.

Lead-acid batteries retain a role where cost is paramount and weight is not a constraint. Advanced carbon-enhanced designs have improved cycle life and partial state-of-charge performance. The established recycling infrastructure of lead-acid makes it attractive for backup power and rural electrification in developing countries. Metal-air batteries offer high theoretical energy densities, but cycle-life and system-complexity challenges have limited commercial deployment. Iron-air batteries targeting 100-h duration entered utility demonstration in 2024–2025 and represent a promising ultra-long-duration pathway using abundant materials.

Supercapacitors store energy electrostatically and deliver very high specific power, up to about 15 kW/kg, with cycle lives exceeding 100,000 cycles and response times below one second [25]. Their low specific energy, typically 3–10 Wh/kg, restricts them to power-quality and ride-through applications. Hybrid systems pairing supercapacitors with batteries combine high power and high energy and are increasingly deployed for fast frequency response. The comparative positioning of the electrochemical and mechanical technologies is shown in the Ragone plot of Figure 3.

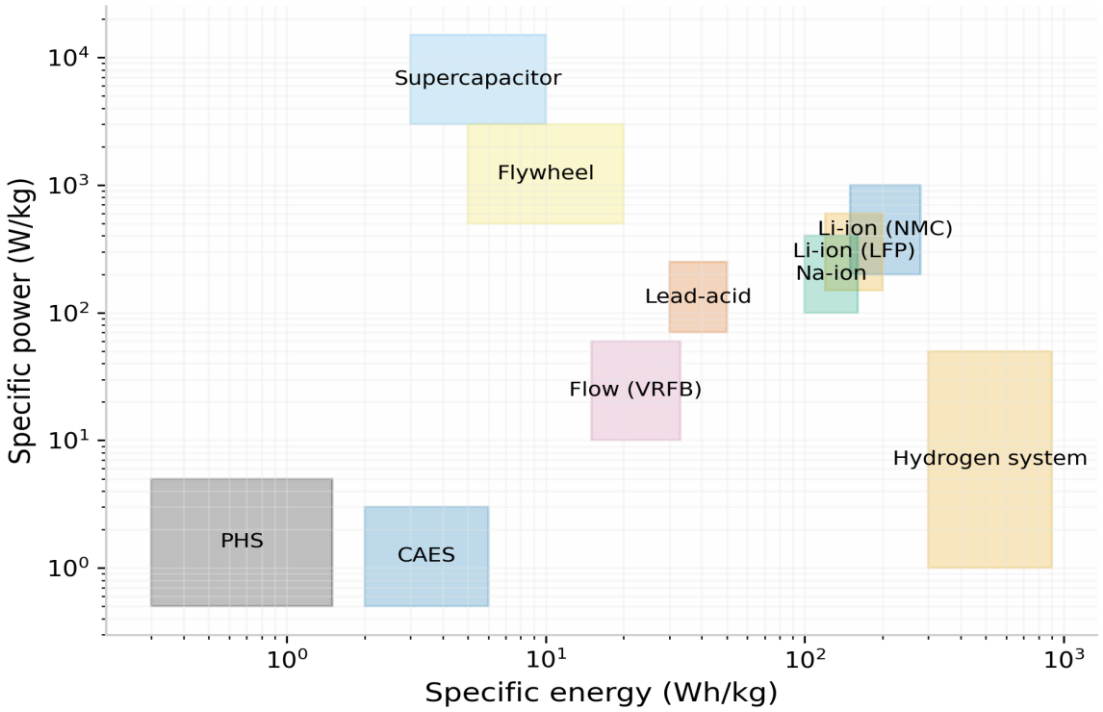


Figure 3: Ragone plot of specific power against specific energy for the storage technologies reviewed. Ranges reflect technology families; hydrogen is plotted on a system basis including tank and balance of plant. Compiled from [11, 25, 26].

2.3 Flow Battery Systems

Flow batteries store energy in liquid electrolytes held in external tanks. Power is set by the cell stack and energy by tank volume. This independent scaling of power and energy makes flow batteries attractive for durations from 4 h to multiple days [27]. Vanadium redox flow batteries (VRFB) are the most commercially advanced variant, with cycle lives exceeding 20,000 cycles at full depth of discharge to an 80% capacity end-of-life criterion. The claim of zero degradation is too strong: vanadium crossover through the membrane, electrolyte imbalance and side reactions cause gradual capacity fade that requires periodic rebalancing. Process-engineering considerations dominate system design. These include electrolyte formulation and vanadium solubility limits, membrane crossover, shunt currents in stacks, pumping parasitic losses of typically 2–5% of rated power, and state-of-charge monitoring for rebalancing [28]. Zinc-bromine systems offer lower material cost and higher energy density, and commercial products are available [28]. Organic

flow batteries using synthesised molecules offer tunable properties at potentially lower cost but remain at earlier development stages [29].
A comparative summary of all major technologies reviewed is given in Table 1.

Table 1: Technology comparison matrix. Round-trip efficiency (RTE) is AC-to-AC including auxiliaries where applicable; cycle life is at the stated depth of discharge to 80% capacity retention; costs are 2025 real USD. Sources: [11, 26, 30, 31].

Technology	Energy density (Wh/kg)	RTE (%)	Cycle life (cycles)	Response time	Typical duration	Capital cost (USD/kWh)	TRL
Li-ion (LFP)	120–200	85–92	4,000–10,000 @80% DoD	<100 ms	0.5–6 h	70–150 (pack)	9
Li-ion (NMC)	150–280	85–92	2,000–5,000 @80% DoD	<100 ms	0.5–4 h	90–180 (pack)	9
Sodium-ion	100–160	85–90	3,000–6,000	<100 ms	2–6 h	80–120 (pack, est.)	8
Lead-acid	30–50	70–85	500–1,500 @50% DoD	<1 s	1–8 h	150–300 (system)	9
VRFB	15–33	65–75	>20,000 @100% DoD	<1 s	4–24 h	300–600 (system)	8–9
Supercapacitor	3–10	90–95	>100,000	<10 ms	seconds–minutes	1,000–2,000 (system)	9
Pumped hydro	0.3–1.5	70–85	asset life 40–80 yr	<1 min	6–20+ h	5–25 (energy basis)	9
CAES (adiabatic)	2–6	60–70 (target)	asset life 30–40 yr	minutes	4–24+ h	10–30 (energy basis)	8
Gravity	~0.28 (100 m lift)	80–85 (claimed)	no cycling degradation	<1 s	4–12 h	150–300 (system, est.)	7–8
Flywheel	5–20	85–95	>100,000	<10 ms	seconds–15 min	1,000–3,000 (system)	8–9
Hydrogen (P2H2P)	300–900 (system)	25–40 (full chain)	stack life in hours	<1 s	days–seasonal	1–5 (storage only)	7–9
Thermal (molten salt)	30–80 (kWh/m³: 40–150)	40–60 (CSP round trip)	asset life 25–30 yr	minutes	6–15 h	20–60	9

3. MECHANICAL ENERGY STORAGE

3.1 Pumped Hydroelectric Storage

Pumped hydroelectric storage (PHS) remains the largest single storage technology by installed capacity, with approximately 189–193 GW in operation worldwide by 2024–2025 [6]. Its share of total storage capacity has nevertheless fallen from over 90% a decade ago to roughly 42% in 2025, because battery additions of 108 GW in 2025 alone far outpaced new pumped hydro construction [3, 6]. In energy terms pumped hydro remains dominant, with roughly 9,000 GWh of storage globally, because typical plants provide 6–20 h of discharge [32]. Round-trip efficiency is 70–85% on an AC-to-AC basis, and variable-speed pump-turbines improve part-load efficiency and provide faster regulation [32]. Asset lifetimes of 40–80 years for civil works and electromechanical equipment underpin low levelised costs [11, 32].
Conventional PHS requires suitable topography. Closed-loop systems using purpose-built reservoirs reduce environmental constraints. The 30 MW Okinawa Yanbaru seawater plant in Japan demonstrated coastal seawater PHS, although it was decommissioned in 2016 and remains a historical demonstration rather than an

operating asset. Underground PHS concepts using abandoned mines or purpose-built caverns could expand deployment to flat regions, and feasibility studies are advancing [32].

3.2 Compressed Air Energy Storage

Compressed air energy storage (CAES) stores energy as compressed air in underground caverns or purpose-built vessels [33]. The two original commercial plants, Huntorf in Germany (290 MW, 1978) and McIntosh in Alabama (110 MW, 1991), have been joined by a new generation of adiabatic facilities in China, including 300 MW-class systems commissioned between 2022 and 2025 [33, 16]. Conventional diabatic CAES burns natural gas during expansion and achieves round-trip efficiencies of 42–54% when gas input is charged to the energy balance [34]. Advanced adiabatic CAES stores the heat of compression and reuses it during expansion. This eliminates fuel consumption and targets efficiencies of 60–70% [34]. The thermodynamic basis matters: isothermal compression minimises work input, real multi-stage compression is polytropic, and exergy destruction occurs in intercooling whenever compression heat is rejected. Cavern volume per MWh stored depends on the operating pressure ratio and storage temperature, and is a key siting constraint. Small-scale aboveground CAES sacrifices energy density for deployment flexibility [35].

3.3 Gravity and Kinetic Storage Systems

Gravity energy storage lifts heavy masses and recovers energy as they descend [36, 37]. The physics explains the low energy density: a mass m raised through height h stores $E = mgh$, so one tonne raised 100 m stores only about 0.27 kWh. Tower-based systems stacking composite blocks and shaft-based systems using disused mine shafts are at demonstration and early commercial stages [36]. Manufacturer-reported round-trip efficiencies of 80–85% for these systems should be treated as claims pending independent verification. Flywheels store kinetic energy in spinning rotors. They offer response times in milliseconds, cycle lives above 100,000, and self-discharge of roughly 3–20% per hour, which confines them to short-duration power-quality and frequency applications.

4. CHEMICAL AND THERMAL STORAGE

4.1 Power-to-X Technologies

Power-to-X technologies convert electricity to chemical energy carriers, enabling long-term storage and sector coupling [38]. Electrolysis is the entry point. The engineering parameters differ by technology. Alkaline electrolysers operate at 0.2–0.5 A/cm², consume 50–55 kWh/kg H_2, and offer stack lifetimes above 60,000 h. Proton exchange membrane (PEM) systems operate at 1–2 A/cm², consume 50–58 kWh/kg H_2, degrade at 5–15 µV/h, and face a genuine material bottleneck in iridium catalyst loading, which constrains scale-up [38, 39]. Solid oxide electrolysis cells (SOEC) operate at elevated temperature and can reach electrical efficiencies up to about 90% on a lower-heating-value basis when external waste heat is counted as a free input; this basis is not comparable with the AC-to-AC efficiencies quoted for other storage technologies [39]. Water consumption is about 9 kg per kg of hydrogen produced, before purification losses.

Hydrogen storage options include compressed gas, cryogenic liquid, metal hydrides, liquid organic hydrogen carriers and geological storage. Salt caverns offer the lowest cost at scale [40]. Storage is not lossless. Liquid hydrogen suffers boil-off of about 0.3–3% per day depending on tank scale. Geological storage requires cushion gas, and compression to 350–700 bar or liquefaction carries energy penalties of 5–15% and about 30% of the energy content respectively [41]. The full power-to-hydrogen-to-power round-trip efficiency, accounting for electrolysis, compression or liquefaction, storage and reconversion, is only about 25–40%. This is the single most important number for assessing hydrogen as a storage medium [38, 41].

Power-to-liquid fuels, including synthetic methane, methanol and Fischer-Tropsch liquids, enable carbon-neutral fuels for aviation and shipping, at round-trip efficiencies of 30–50% [42]. Ammonia offers higher volumetric energy density than hydrogen and established production infrastructure [43]. Green ammonia demonstration as a marine fuel has progressed, with the first ammonia-fuelled vessels entering service in 2025–2026 rather than merely being expected.

4.2 Thermal energy storage

Thermal energy storage (TES) stores energy as heat or cold [44]. Sensible heat storage in molten salts at 300–600 °C provides storage densities of 40–150 kWh/m³ and enables 6–15 h of discharge in concentrating solar power plants. The 110 MW Crescent Dunes plant in Nevada demonstrated 10 h of molten-salt storage but ceased operation in 2019 after a salt tank failure. The failure mode is instructive: containment integrity and freeze-protection engineering are as important as the storage medium. Latent heat storage with phase change materials offers 50–150 kWh/m³ with latent heats of 150–250 kJ/kg for organic materials, but low thermal conductivity requires enhancement through encapsulation or conductive additives [45]. Thermochemical storage offers the highest densities, 120–250 kWh/m³, and minimal standing losses, but remains at research and demonstration stage [46]. A newer class of low-cost solid-media storage has moved to commercial demonstration between 2024 and 2026: sand and crushed-rock systems store resistively heated energy at 500–1,000 °C for days to weeks at very low material cost, and commercial sand batteries are operating in Finland. The exergetic quality of stored heat must be recognised: a kilowatt-hour stored at 600

°C is worth far more than one at 90 °C, and second-law efficiency rather than first-law efficiency is the meaningful metric for thermal systems [44, 46].

5. GRID INTEGRATION AND APPLICATIONS

5.1 Grid Services, Frequency Products And System Stability

Energy storage provides a diverse range of grid services [9]. Frequency services divide into recognised product categories with materially different requirements. Primary frequency control requires response within seconds and sustainment of minutes. Secondary control operates over minutes. Tertiary control and replacement reserves operate over 15 min to hours. Fast frequency response products, created in markets such as Australia and the UK, reward sub-second response. Battery storage can meet all of these with high accuracy [47]. The deeper stability challenge in high-renewable systems is the loss of synchronous inertia as conventional generators retire [48]. Grid-following inverters synchronise to the measured grid frequency and cannot independently stabilise a weak grid. Grid-forming inverters instead set a voltage reference and can provide synthetic inertia, withstand high rates of change of frequency, and support system strength and black start [49]. Grid-forming battery storage is now specified in procurement in Australia and parts of Europe and is arguably the most important recent development in storage applications. Voltage support and reactive power from storage inverters can reduce the need for capacitor banks and voltage regulators in distribution networks [50]. The duration requirements of the principal grid services are mapped in Figure 4.

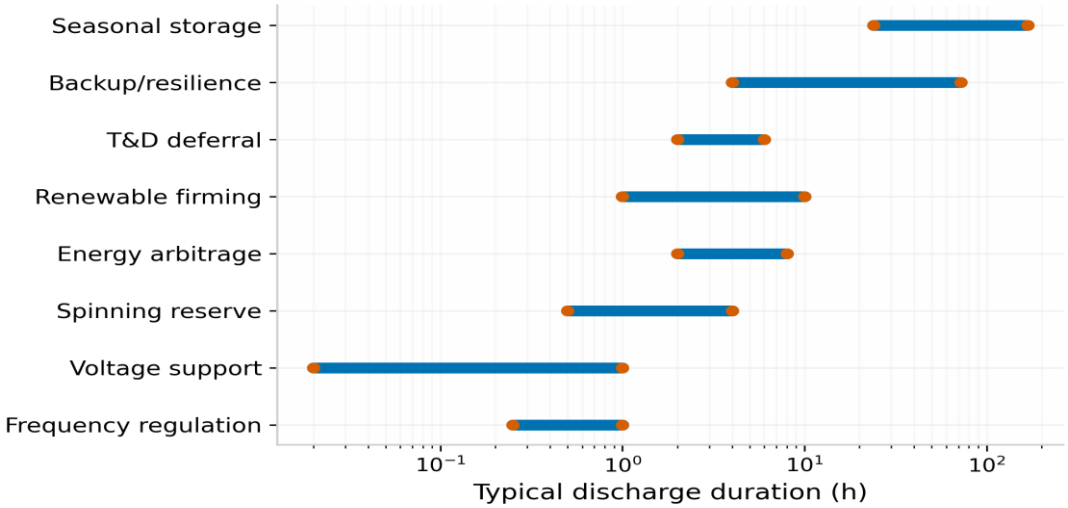


Figure 4: Typical discharge duration requirements by grid application (log scale; range plot). Requirements are indicative and vary by jurisdiction; seasonal storage spans 1–7 days. Compiled from [9, 49, 26].

5.2 Renewable energy integration

The technical requirements of each service and the technologies able to meet them are mapped in Table 3.

Table 3: Grid service–duration–technology mapping. Sources: [9, 49, 47].

Grid service	Response time	Duration	Suitable technologies
Fast frequency response	<1 s	15–60 min	Li-ion, supercapacitor, flywheel
Primary frequency control	seconds	minutes	Li-ion, flywheel, PHS (variable speed)
Synthetic inertia / system strength	<100 ms	seconds	Grid-forming battery inverters
Voltage support	<1 s	continuous	Battery inverters, synchronous condensers
Spinning/contingency reserve	seconds–minutes	0.5–4 h	Li-ion, PHS, CAES
Energy arbitrage	minutes	2–8 h	Li-ion, VRFB, PHS
Renewable firming	minutes	1–10 h	Li-ion, VRFB, CAES
T&D deferral	minutes	2–6 h	Li-ion, VRFB
Black start	<1 min	0.5–2 h	Grid-forming batteries, PHS
Seasonal balancing	hours	days–weeks	Hydrogen, CAES, thermal, PHS

5.2 Renewable Energy Integration

Solar generation peaks at midday while demand peaks in the evening. Storage shifts solar energy to evening hours and mitigates the steep evening ramp [7]. Wind variability spans minutes to seasons. Studies indicate that 4–8 h of storage addresses most integration challenges up to 50–70% renewable penetration, while higher shares need longer-duration storage or sector coupling [7, 13]. Storage also reduces curtailment, and curtailment improves storage economics only where storage can access the curtailed energy and price spreads persist [10]. Important feedback now shapes the economics: as storage deployment grows, arbitrage narrows the very price spreads that make arbitrage profitable. This self-cannibalisation effect is documented in markets with rapid battery growth and must be included in revenue forecasts. Co-located and hybrid projects remain common; about 24 GW of utility-scale battery additions in 2025 were co-located with renewables globally [3].

5.3 Behind-the-Meter Applications

Behind-the-meter storage offers bill savings, backup power and grid-services participation [51]. Indicative payback periods range from 4–7 years for commercial demand-charge management in high-tariff markets to 8–12 years for residential solar-plus-storage, and are shortest where tariff spreads are wide or diesel backup is displaced. Resilience value is increasingly recognised, and methods now exist to monetise it [52]. Aggregation through virtual power plants lets thousands of distributed batteries participate in wholesale markets, a model enabled in the United States by FERC Order 2222 [53, 54]. Regional deployment trends over the review period are shown in Figure 5.

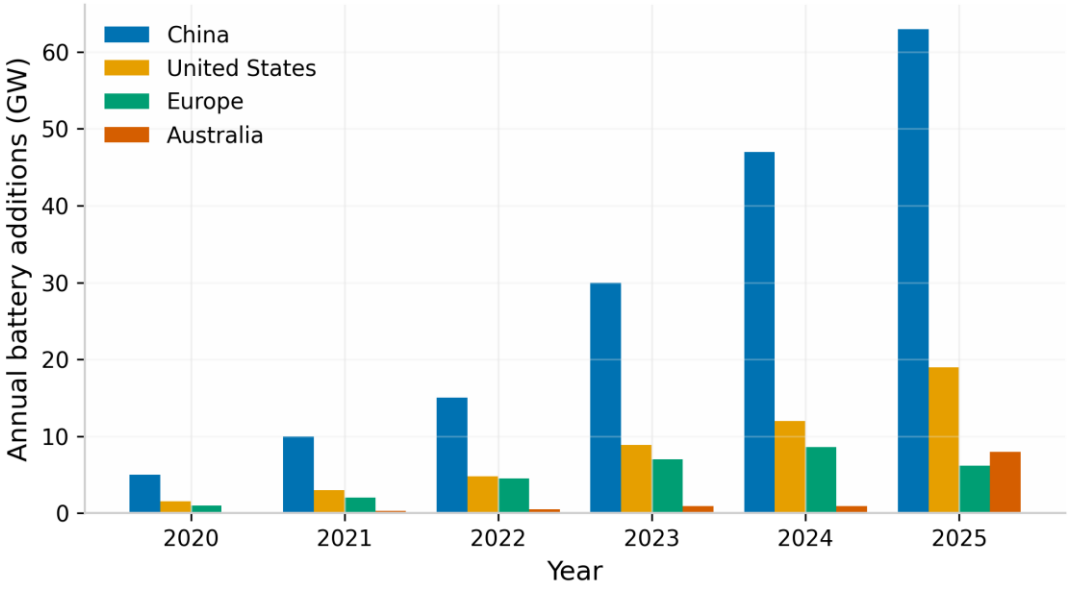


Figure 5: Annual battery storage capacity additions by region, 2020–2025 (GW). China added just over 63 GW in 2025, the United States 19 GW, Europe 6.2 GW and Australia nearly 8 GW. Data source: IEA [3].

6. ECONOMIC ANALYSIS AND MARKET TRENDS

6.1 Cost Trends, Learning Curves and Levelised Cost of Storage

Lithium-ion pack prices fell from about USD 1,191/kWh in 2010 to USD 139/kWh in 2023, USD 115/kWh in 2024 and USD 108/kWh in 2025, a cumulative decline of about 93% in nominal terms [1, 2]. The 2022 increase to USD 151/kWh, driven by lithium carbonate prices, is an important departure from the learning curve and shows that commodity cycles can override learning effects in the short run [55]. Learning rates of 18–20% per doubling of cumulative production characterise the long-run trend [56, 55]. Turnkey utility-scale system costs fell about 40% between 2023 and 2024 to a global average near USD 165/kWh, with marked regional divergence: about USD 101/kWh in China, USD 236/kWh in the United States and USD 275/kWh in Europe. All cost figures herein are nominal USD unless stated; where levelised values are quoted they are in 2025 real USD.

The appropriate comparative metric is the levelised cost of storage (LCOS). Following the framework of Schmidt et al. [56], LCOS is defined as:

LCOS = [CAPEX + Σt (O&Mt + Et,charge·pch + Dt) / (1+r)^t] / [Σt Et,dis / (1+r)^t]

where CAPEX is capital expenditure in USD/kWh, O&M is annual operating cost, Et,charge is annual charged energy, pch is the charging electricity price, Dt is degradation-driven augmentation or replacement in year t, r is the discount rate, and Et,dis is annual discharged energy, which equals throughput times depth of discharge times round-trip efficiency. LCOS is highly sensitive to cycle count, discount rate and degradation.

Table 2 presents indicative LCOS values by technology and duration, and Figure 6 shows the duration dependence graphically.

Table 2: Indicative levelised cost of storage by technology and discharge duration (2025 real USD/MWh; 250–350 cycles/yr, 8% discount rate, 20-yr life unless stated). Sources: [56, 30, 26].

Technology	1 h	4 h	8 h	24+ h
Li-ion (LFP)	250–400	150–250	140–220	not economic
VRFB	350–500	220–320	180–260	140–200
Pumped hydro	n/a	80–150	70–130	60–120
CAES (adiabatic)	n/a	150–250	120–200	90–160
Hydrogen (P2H2P)	n/a	400–600	300–500	150–300
Thermal (molten salt)	n/a	120–200	100–160	80–140

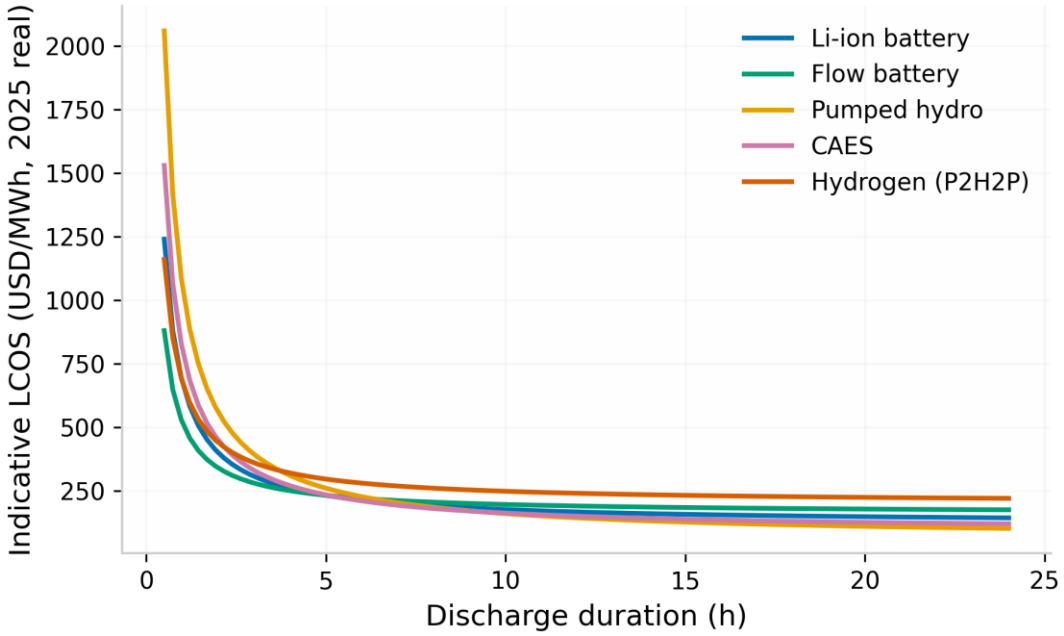


Figure 6: Indicative LCOS against discharge duration (2025 real USD/MWh). Batteries dominate short durations; pumped hydro, CAES and hydrogen become competitive at long durations. Derived from [56, 30].

6.2 Market Structures, Business Models and Financing

Storage earns revenue from energy arbitrage, ancillary services, capacity mechanisms and behind-the-meter savings, and stacking multiple streams is usually necessary for viability [14, 57]. Indicative ancillary-service revenues have ranged from USD 50,000–150,000 per MW-year in mature frequency markets, though prices fall as markets saturate. Financing terms are decisive: at an 8–10% cost of capital typical of developed markets, lithium-ion LCOS is roughly 30–40% lower than at the 15–20% common in many African markets, for identical hardware. De-risking instruments and concessional finance are therefore as important as technology cost in developing regions [58]. Principal uncertainties in cost projections include raw material price cycles, regional supply-chain policy, learning-rate persistence and degradation assumptions [55].

7. POLICY AND REGULATORY FRAMEWORKS

7.1 International Policy Landscape

Storage policy continues to develop mainly at national level. Nationally determined contributions under the Paris Agreement increasingly reference storage. India has adopted a national framework promoting energy storage systems, and China exceeded its 30 GW by 2025 new-type storage target ahead of schedule, prompting upward revision of subsequent targets [59, 60]. Development finance institutions are expanding support: the World Bank and African Development Bank have committed concessional finance to mini-grid and storage programmes across sub-Saharan Africa [58].

7.2 National and Regional Policies

Direct incentives, procurement mandates and market reform have driven deployment in the major markets [61]. FERC Order 841 opened wholesale markets to storage in the United States, and Order 2222 subsequently opened them to distributed resource aggregations [62, 54]. Public research support continues

through national battery programmes [31]. Safety regulation has become a distinct policy domain. The key instruments are NFPA 855 for stationary storage installation, UL 9540 for system listing, UL 9540A for large-scale fire testing, and the IEC 62933 series for system standards, alongside IEC 63056 for lithium cell safety. The policy instruments of the main jurisdictions are summarised in Table 4.

Table 4: Policy instruments by jurisdiction. Sources: [62, 54, 60, 59, 63, 61].

Jurisdiction	Instrument	Year	Type	Observed effect
United States	Investment Tax Credit (standalone storage)	2022	Fiscal incentive	Accelerated utility-scale deployment
United States	FERC Order 841	2018	Market access	Wholesale market participation by storage
United States	FERC Order 2222	2020	Market access	Aggregation of distributed resources
China	New-type storage mandate (14th FYP)	2021	Deployment target	>30 GW exceeded ahead of 2025 target
China	2025 market reform (co-location mandate removal)	2025	Market reform	Shift to merchant storage; co-location share fell
European Union	Electricity market design reform	2024	Market reform	Improved flexibility remuneration
India	National Framework for Energy Storage	2023	Policy framework	Viability gap funding and targets
Nigeria	Electricity Act 2023	2023	Sector reform	State-level markets; mini-grid enablement
Nigeria	NERC Mini-Grid Regulations	2026	Regulation	Permits up to 5 MW isolated / 10 MW interconnected
International	NFPA 855 / UL 9540A / IEC 62933	2019–2024	Safety standards	Siting, testing and installation requirements

8. CASE STUDIES

8.1 Hornsdale Power Reserve, Australia

The Hornsdale Power Reserve in South Australia, commissioned in 2017 at 100 MW/129 MWh and later expanded to 150 MW/194 MWh using Tesla Powerpack technology, remains a landmark demonstration of grid-scale battery storage [64]. It provides frequency regulation, contingency reserves and renewable firming, and delivered substantial cost savings through fast frequency response. Its success catalysed national deployment: Australia added nearly 8 GW of battery capacity in 2025, almost nine times the previous year, and storage now represents about 18% of the country's installed dispatchable capacity [3]. New market products for fast-responding resources were developed in response to the capabilities Hornsdale demonstrated.

8.2 Moss Landing Energy Storage Facility, USA: a safety case study

The Moss Landing site in California comprises three battery facilities of 300 MW, 350 MW and 100 MW. On 16 January 2025, a major fire broke out in the 300 MW building, which held about 100,000 lithium-ion modules; approximately 55% were damaged. About 1,200 nearby residents were evacuated, the fire burned for several days, and a reignition occurred on 18 February 2025 [5]. Battery removal proceeded under United States Environmental Protection Agency oversight and continued into 2026. The operator determined that the affected facility would not return to service. Post-incident monitoring detected heavy-metal fallout in surrounding wetlands. The lessons are significant. First, indoor configurations concentrate propagation risk, and the industry has since moved towards outdoor, separated enclosures. Second, thermal runaway propagation between modules must be assessed through UL 9540A testing before siting approval. Third, emergency response planning and community notification must be integral to project permitting [5, 65].

Presented honestly, Moss Landing is one of the most instructive case studies in the literature: it shows that fire safety engineering must scale with deployment.

8.3 Mini-grid storage in Nigeria: the developing-country case

A developing-country case study is essential for balance. Under the Nigeria Electrification Project and Rural Electrification Agency programmes, solar-hybrid mini-grids with battery storage have been deployed to underserved communities and institutions across Nigeria, displacing diesel generation [58, 63]. The commercial case rests on diesel displacement economics: diesel generation typically costs USD 0.30–0.50/kWh in the region, against solar-plus-storage levelised costs now frequently below USD 0.20/kWh. The NERC Mini-Grid Regulations 2026, which replaced the 2023 Regulations, raised permitted capacity to 5 MW for isolated mini-grids and 10 MW for interconnected mini-grids, expanding the addressable market [63]. Operating experience highlights the importance of thermal management, dust protection and local maintenance capacity, themes developed in Section 9. The three case studies are summarised in Table 5.

Table 5: Summary of case studies. Sources: [64, 5, 58, 3].

Project	Rating	Duration	Chemistry/type	Year	Services	Outcome
Hornsdale, Australia	150 MW / 194 MWh	~1.3 h	Li-ion (NMC)	2017 (exp. 2020)	Frequency control, firming, reserves	Exceeds expectations; catalysed national market
Moss Landing, USA	300 + 350 + 100 MW	~4 h	Li-ion	2020–2023	Resource adequacy, integration	Jan 2025 fire; 300 MW unit retired; safety lessons
Nigeria mini-grids (REA/NEP)	kW–MW scale	4–8 h	Li-ion / lead-acid	2019–2026	Diesel displacement, energy access	Operating; strong commercial case vs diesel

9. ENERGY STORAGE IN THE AFRICAN CONTEXT

9.1 Weak Grids And Diesel Displacement

Technical requirements in sub-Saharan Africa differ materially from those in strong interconnected grids. Grids are weak, outages are frequent, and the dominant commercial case is diesel displacement for commercial and industrial users rather than arbitrage. With diesel at USD 0.30–0.50/kWh, solar-plus-storage is frequently the cheapest reliable option, and payback periods of 3–6 years are achievable [58]. Mini-grids combining solar, batteries and diesel backup are scaling under the Nigeria Electrification Project and comparable programmes [63, 58].

9.2 Regulation and Finance

The Electricity Act 2023 decentralised electricity regulation in Nigeria and empowered state-level markets [66]. The NERC Mini-Grid Regulations 2026 raised permitted capacities and clarified interconnection [63]. Development finance from the World Bank and African Development Bank underpins most large programmes [58]. Because costs of capital of 15–20% are common in the region, concessional finance and guarantees have a larger effect on viability than further hardware cost reductions.

9.3 High-Temperature Operation

Lithium-ion degradation is strongly temperature-dependent, and calendar ageing rates roughly double for every 10 °C rise [18]. Systems designed for temperate climates require derating, enhanced thermal management and revised warranty terms at 30–40 °C ambient. Dust ingress and humidity add further design constraints, favouring sealed enclosures with filtered or liquid cooling. This engineering point is under-addressed in the international literature and is directly relevant to equipment selection and lifetime economics across the region.

9.4 Critical Minerals and Second-Life Batteries

Africa holds major shares of global cobalt (Democratic Republic of Congo) and emerging lithium resources (including Nigeria, Zimbabwe and Namibia). The strategic question is whether countries export raw material or capture value through processing and cell manufacture [12]. Second-life electric vehicle batteries, retaining 70–80% of original capacity, could provide low-cost stationary storage for African markets, though testing, certification and business models remain immature [67].

10. CHALLENGES AND FUTURE DIRECTIONS

10.1 Material Sustainability and Recycling

Supply chains for lithium, cobalt and nickel face concentration and sustainability concerns [12]. Battery recycling follows three routes. Pyrometallurgy recovers cobalt, nickel and copper at high recovery but loses lithium and is energy-intensive. Hydrometallurgy recovers lithium, cobalt, nickel and manganese at recoveries often exceeding 90% with lower energy demand, and dominates new capacity. Direct recycling preserves cathode structure and offers the best economics where sorting allows, but remains at pilot scale [68]. Recycling capacity is expanding fastest in China and is a strategic policy priority in the United States and Europe.

10.2 Long-Duration and Seasonal Storage

Most battery deployments provide 4 h or less, while deep decarbonisation requires multi-day and seasonal balancing [13]. Hydrogen, CAES, pumped hydro and thermal storage are the candidate pathways, and iron-air batteries entered 100-h demonstrations in 2024–2025. Long-duration additions are projected to quadruple in 2026, concentrated in China [16]. Market mechanisms rarely reward duration explicitly; capacity products with tiered duration requirements are a promising reform.

10.3 Market Frameworks

Markets often fail to compensate the full service stack, and regulatory complexity raises transaction costs [14]. Cannibalisation of arbitrage spreads adds a further challenge as deployment grows. Market design should reward duration, locational value and grid-forming capability.

10.4 Safety

Thermal runaway is initiated when exothermic decomposition reactions outpace heat dissipation, with onset typically between 90 °C and 200 °C depending on chemistry and state of charge [65]. Decomposition releases vent gases containing hydrogen, carbon monoxide and hydrogen fluoride, and propagation between cells and modules drives incident scale, as the Moss Landing fire demonstrated [5, 19]. Mitigation requires cell-to-cell propagation resistance verified by UL 9540A testing, deflagration venting, spacing and detection, and trained emergency response. Compliance with NFPA 855, UL 9540 and IEC 62933 should be a precondition of permitting.

10.5 Life Cycle Assessment and Embodied Carbon

Storage carries embodied emissions of roughly 40–100 kg CO_2e per kWh of installed lithium-ion capacity, dominated by cell manufacturing energy [69]. The carbon payback period depends on the generation displaced and is typically months to a few years for storage charged by renewables. Energy payback and life cycle assessment should be reported routinely for storage projects.

10.6 Developing-Country Challenges

Deployment in developing countries faces high ambient temperatures, dust and humidity, weak grid interconnection, limited local operation-and-maintenance capacity, absence of local testing facilities, import duties on components, and end-of-life handling in jurisdictions without recycling infrastructure [58, 18].

10.7 Digitalisation and Cyber-Security

Machine learning now supports dispatch optimisation and state-of-health estimation, and digital twins are entering battery asset management [70]. Grid-connected storage is also a cyber-physical target; communications, firmware and aggregation platforms require security-by-design and compliance with grid cyber-security standards [71].

4. CONCLUSION

The study is limited by reliance on secondary cost data, the currency of grey literature for 2025–2026 figures, and the exclusion of laboratory-scale technologies. Subject to these limitations, five conclusions correspond to the five objectives.

i. On technologies: lithium-ion dominates short-duration storage, with LFP exceeding 90% of 2025 stationary additions, but no single technology spans all timescales. Pumped hydro provides most stored energy globally, and flow batteries, CAES, hydrogen and thermal storage are required for long durations. A diversified portfolio is essential.

ii. On economics: pack prices fell 93% between 2010 and 2025 to USD 108/kWh, and stationary packs reached USD 70/kWh. LCOS analysis shows lithium-ion competitive below 4–6 h and mechanical or chemical storage competitive beyond it. Regional cost divergence of more than twofold, and the 2022 price reversal, show that commodity and policy cycles can dominate learning effects.

iii. On applications: storage already provides the full range of grid services, and grid-forming capability has emerged as the decisive response to declining synchronous inertia. In developing regions, diesel displacement, not arbitrage, is the dominant value stream.

iv. On policy: deployment follows policy. Investment incentives, market access rules such as FERC Orders 841 and 2222, and deployment targets have each demonstrably accelerated markets, while safety standards (NFPA 855, UL 9540A, IEC 62933) must now scale with deployment, as the Moss Landing fire showed.
v. On challenges: the principal gaps are long-duration storage, recycling at scale, financing costs in developing markets, and high-temperature engineering. Addressing them requires sustained R&D, duration-aware market products, concessional finance and region-specific design standards.
Actionable recommendations follow. Policymakers should adopt duration-tiered capacity products, mandate UL 9540A-based permitting, and use concessional finance to close the cost-of-capital gap in developing markets. Industry should design explicitly for high-temperature operation, publish independently verified performance data, and invest in recycling. Researchers should prioritise low-cost long-duration chemistries, direct recycling, grid-forming control, and degradation modelling for tropical climates.

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