EPRI

LDES
LONG DURATION
ENERGY STORAGE
COUNCIL

Cost Benchmarking for Long Duration Energy Storage Solutions

2025 Technical Report

January 2026

ACKNOWLEDGMENTS

EPRI prepared this report in collaboration with the LDES Council.

The Principal Investigators were: G. Booras, J. Marasigan, J. Raade, J. Rushkoff and S. Hume.

EPRI acknowledges the strong partnership and collaboration of the LDES Council and its member organizations in supporting this research effort. The contributions of Council members—through their technical insights, market perspectives, and ongoing engagement— were instrumental in shaping the findings and ensuring that the outcomes reflect real-world priorities and opportunities for long duration energy storage deployment.

EPRI and the LDES Council recognize and value the collective effort of all participants who contributed knowledge, expertise, and guidance. Their commitment to advancing the energy storage industry continues to drive progress toward a more resilient, reliable, and decarbonised energy system.

ABSTRACT

This study presents the results of a cost benchmarking study for long duration energy storage (LDES) technologies conducted by EPRI in collaboration with the LDES Council. Recognizing the need to have high-quality data on the cost of LDES technologies to enable policymakers and data collectors to support the modeling, demonstration, and large-scale deployment of LDES solutions, the LDES Council issued a survey to its technology developer members to collect high-level performance metrics, capital and operating costs, and technology readiness levels for commercial-scale projects in both power-to-power and power-to-heat applications.

The collected data were reviewed and normalised to a common design basis and location to enable meaningful comparisons across technologies. The names of individual technology developers were not included given confidentiality restrictions. However, the data are presented in an aggregated format with related technologies included in five broad technology categories, including: Intraday Electrochemical, Intraday Compressed Gas, Intraday Pumped Heat, Multi-Day, and Thermal Energy Storage. Cost data were scaled and aggregated for contract years 2025 and 2030, providing insights into expected cost reductions driven by research and development advancements and manufacturing scale-up. Cost data were also aggregated to avoid over-interpreting individual technology performance, e.g., to preserve confidentiality and comparability.

Note to Readers: To ensure comparability and protect commercially sensitive information, this study presents cost data in aggregated ranges by technology category. Readers seeking more granular or technology-specific information for modeling or planning purposes are encouraged to contact the LDES Council, which can facilitate connections with relevant technology developers represented in this study.

EXECUTIVE SUMMARY

This report presents the results of a comprehensive cost benchmarking study for long duration energy storage (LDES) technologies, conducted by EPRI in collaboration with the LDES Council. The study addresses the growing need for reliable, scalable, and cost-effective energy storage solutions to support grid reliability, decarbonization, and the increasing energy demands driven by data centres, electrification, and artificial intelligence.

Study Overview

- A structured survey was issued to LDES Council technology developer members.
- Data collected included capital costs, operating and maintenance (O&M) costs, performance metrics, and technology readiness levels (TRLs).
- Technologies were grouped into five categories:
  - Intraday Electrochemical (e.g., flow batteries, sodium batteries)
  - Intraday Compressed Gas (e.g., advanced compressed air, liquid air, CO_2-based systems)
  - Intraday Pumped Heat Energy Storage (power-to-power configuration)
  - Multi-Day (100+ hr options, e.g., fuel-based, reversible fuel cells, metal-air batteries, etc.)
  - Thermal Energy Storage (power-to-heat systems such as sensible heat or phase-change materials)
- Data were normalised to a common design basis and location (U.S. Lower 48) to enable meaningful comparisons.

Key Cost Data

The low and high ranges for total plant cost (TPC) in $/kWh for each technology group are plotted in the following figures for current costs in 2025 and for projected costs in 2030. All technology categories show costs in units of electrical energy storage (power-to-power applications) except for Thermal Energy Storage, which is shown in units of thermal energy storage (power-to-heat application). TPC values expressed in $/kWh should be interpreted in the context of discharge duration and intended system application, as longer duration resources inherently spread fixed power-related costs over more stored energy.

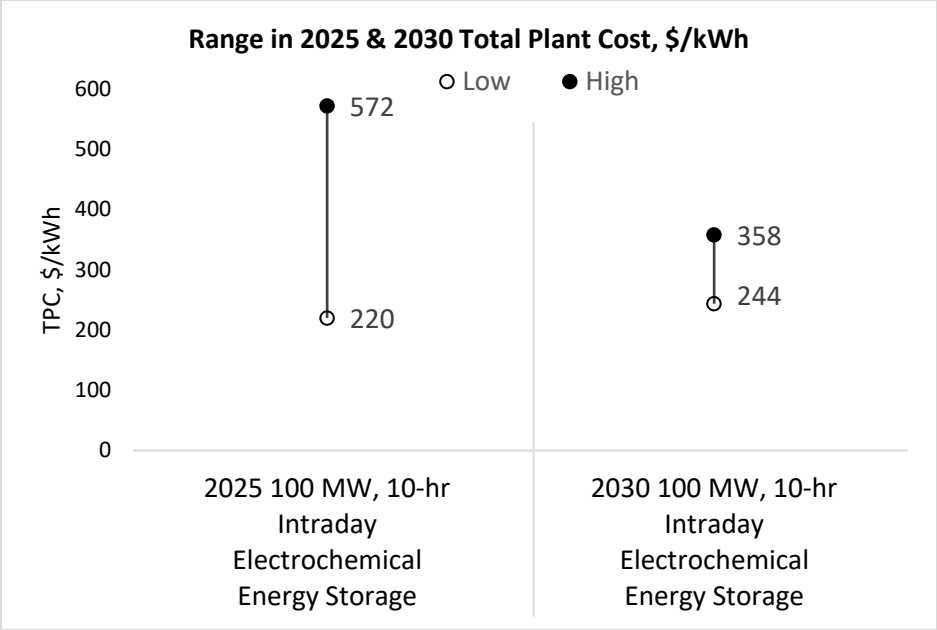


Figure 1. Range in 2025 and 2030 TPC in $/kWh for Intraday Electrochemical Energy Storage category

Note that the Intraday Electrochemical technologies that make up the 2030 group are not the same as those in 2025, i.e., some developers only provided 2025 costs, some both 2025 and 2030 costs, and some only 2030 costs. Based on the submitted cost data, the projected TPC cost reduction from 2025 to 2030 for the Intraday Electrochemical Energy Storage category averages ~37%.

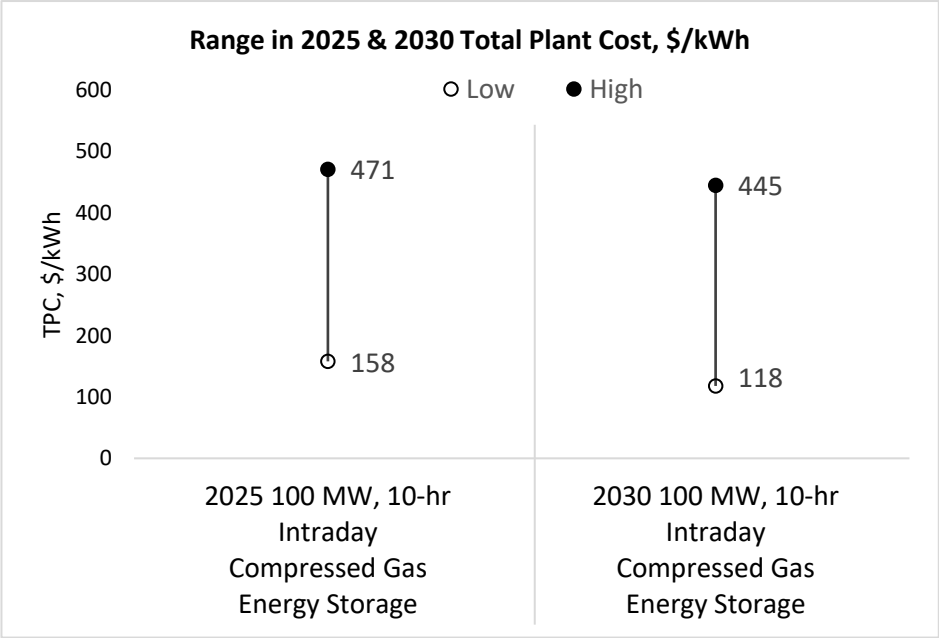


Figure 2. Range in 2025 and 2030 TPC in $/kWh for Intraday Compressed Gas Energy Storage category

Based on the submitted cost data, the projected TPC cost reductions from 2025 to 2030 for the Compressed Gas Energy Storage category range from 6-25%.

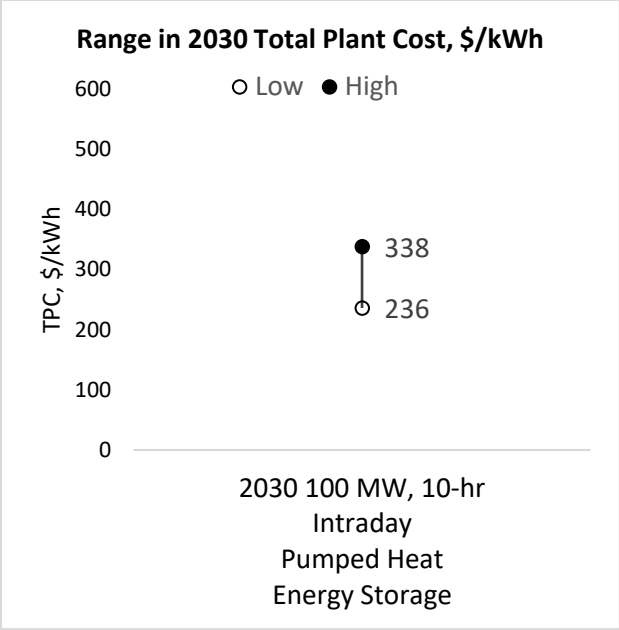


Figure 3. Range in 2030 TPC in $/kWh for Intraday Pumped Heat Energy Storage category

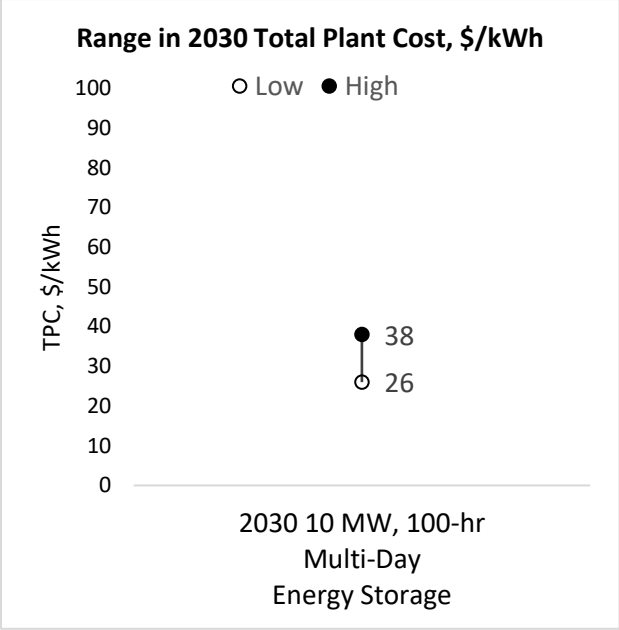


Figure 4. Range in 2030 TPC in $/kWh for Multi-Day Energy Storage category

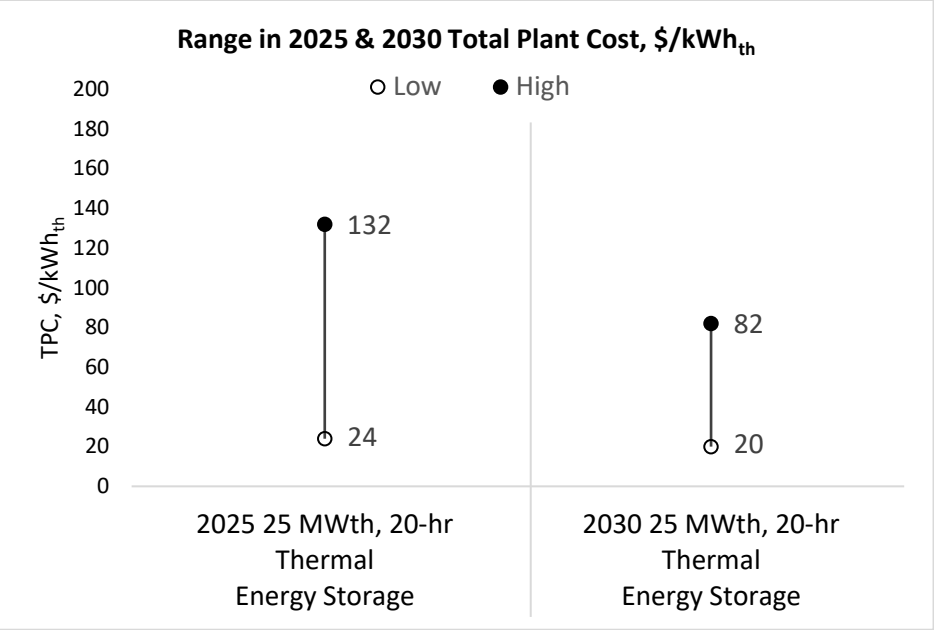


Figure 5. Range in 2025 and 2030 TPC in $/kWh$_{th}$ for Thermal Energy Storage category

Note that the technologies that make up the 2030 group are not the same as those in 2025, i.e., some developers only provided 2025 costs, while others provided both 2025 and 2030 costs. Based on the submitted cost data, the projected TPC cost reductions from 2025 to 2030 for the Thermal Energy Storage category range from 16-47%.

Conclusions

- The technology developers active in the industry who provided costs for both contract years expect substantially lower costs in 2030 versus 2025. Expected cost reductions by 2030 are driven by ongoing work, improved performance, and economies of scale from expanded manufacturing.
- The aggregated and normalised cost data provide actionable insights for utilities and system operators to incorporate LDES technologies into resource planning and capacity expansion models
- The benchmarking methodology enables consistent comparison across diverse technologies and supports planning, modeling, and investment decisions
- Differences between LDES Council data and other references highlight the need for harmonized cost definitions and broader technology coverage to allow fair comparisons

ACRONYMS AND ABBREVIATIONS

Abbreviation	Definition
ATB	Annual Technology Baseline
BESS	Battery energy storage system
BOP	Balance-of-plant
CAPEX	Capital expenditure
HTF	Heat transfer fluid
LAES	Liquid air energy storage
LDES	Long duration energy storage
LFP	Lithium iron phosphate
MW	Megawatt electric
MW_{th}	Megawatt thermal
MWh	Megawatt-hour electric
MWh_{th}	Megawatt-hour thermal
NLR	National Laboratory of the Rockies
O&M	Operating and maintenance
P2H	Power-to-heat
P2P	Power-to-power
PCM	Phase-change material
PHES	Pumped heat energy storage
RFB	Redox flow battery
RTE	Round-trip efficiency
TES	Thermal energy storage
TIC	Total installed cost
TPC	Total plant cost
TRL	Technology readiness level
VRB	Vanadium redox flow battery

CONTENTS

1. **Introduction 1**

Motivation 1

Approach 2

Actionable LDES Information for Industry Stakeholders 2

Utility Resource Planning 3

2. **Survey Development 5**

3. **TRL Assessment 6**

4. **Data Collection and Review 7**

Data Collection 7

Data Review 7

TRL Assessment 7

Cost Information 7

Resource Characteristics 8

5. **Data Analysis 9**

Technology Categorization 9

Intraday Electrochemical Energy Storage 9

Intraday Compressed Gas Energy Storage 12

Intraday Pumped Heat Energy Storage 14

Multi-Day Energy Storage 16

Thermal Energy Storage 17

Data Normalisation 20

Normalising Costs to a Common Design Basis 20

Normalising Costs to a Common Location 21

Cost Data Aggregated Results 21

Intraday Electrochemical Energy Storage 23

Intraday Compressed Gas Energy Storage 25
Intraday Pumped Heat Energy Storage 27
Multi-Day Energy Storage 29
Thermal Energy Storage 30
Cost References 33

6. **Summary and Conclusions 35**
Key Conclusions 35
Recommendations 36

7. **References 37**

A. **Blank Survey 38**
Instructions, Item Descriptions Worksheet 39
Power-to-Power Survey Worksheet 41
Power-to-Heat Survey Worksheet 43

B. **TRL Criteria 45**

C. **Details on Scaling Costs 47**

LIST OF FIGURES

Figure 1. Range in 2025 and 2030 TPC in $/kWh for Intraday Electrochemical Energy Storage category v
Figure 2. Range in 2025 and 2030 TPC in $/kWh for Intraday Compressed Gas Energy Storage category v
Figure 3. Range in 2030 TPC in $/kWh for Intraday Pumped Heat Energy Storage category vi
Figure 4. Range in 2030 TPC in $/kWh for Multi-Day Energy Storage category vi
Figure 5. Range in 2025 and 2030 TPC in $/kWh$_{th}$ for Thermal Energy Storage category vii
Figure 6. Simplified diagram of a NaS battery cell 10
Figure 7. Diagram of a VRB 11
Figure 8. Range in 2025 and 2030 TPC in $/kWh for Intraday Electrochemical Energy Storage category 25
Figure 9. Range in 2025 and 2030 TPC in $/kWh for Intraday Compressed Gas Energy Storage category 27
Figure 10. Range in 2030 TPC in $/kWh for Intraday PHES category 28
Figure 11. Range in 2030 TPC in $/kWh for Multi-Day Energy Storage category 30
Figure 12. Range in 2025 and 2030 TPC in $/kWh$_{th}$ for Thermal Energy Storage category 32

LIST OF TABLES

Table 1. Resource characteristics for Intraday Electrochemical Energy Storage technologies 12
Table 2. Resource characteristics for Intraday Compressed Gas Energy Storage technologies 14
Table 3. Resource characteristics for Intraday PHES technologies in P2P configuration 16
Table 4. Resource characteristics for Multi-Day Energy Storage technologies 17
Table 5. Resource characteristics for TES technologies 20
Table 6. Scaled sizes for technology categories 21
Table 7. Aggregated 2025 cost data for Intraday Electrochemical Energy Storage category 24
Table 8. Aggregated 2030 cost data for Intraday Electrochemical Energy Storage category 24
Table 9. Aggregated 2025 cost data for Intraday Compressed Gas Energy Storage category 26
Table 10. Aggregated 2030 cost data for Intraday Compressed Gas Energy Storage category 26
Table 11. Aggregated 2030 cost data for Intraday PHES category 28
Table 12. Aggregated 2030 cost data for Multi-Day Energy Storage category 29
Table 13. Aggregated 2025 cost data for TES category 31
Table 14. Aggregated 2030 cost data for TES category 31
Table 15. 2025 cost references for LFP lithium-ion and PSH 34

INTRODUCTION

Motivation

Utilities, energy companies, industrial companies, and electricity consumers have a diverse set of pathways to achieve their system reliability, energy affordability, and decarbonization goals. The rapid growth of energy consumption driven by data centres, the use of artificial intelligence, and the trend towards electrification is driving the search for new sources of scalable, dispatchable power and heat. Long duration energy storage (LDES) is an enabler for these objectives and is important for companies to consider as part of a portfolio of solutions. LDES comprises an array of primarily developing energy storage technologies that aspire to be available at lower costs than alternative technologies and capable of providing diverse services required to keep the grid stable and reliable and the energy industry sustainable. LDES can provide a range of energy services including electrical energy, capacity, resilience, balancing and reserves, and low-carbon heat. When considering LDES, it is important to start with the desired use case in mind, then select the technology that can best provide the services when needed [1].

LDES is complementary to the growing fleet of grid energy storage resources currently represented almost entirely by lithium-ion batteries and pumped storage hydropower, which serve as critical benchmarks for evaluating emerging LDES technologies. LDES is commonly defined as a technology that stores energy and then dispatches it as power, heat, or cooling for extended periods of time, ranging from 8 hours to days, weeks, or seasons. Many short-duration energy storage systems can be operated like LDES if they are discharged at lower power levels. However, they may lack the low marginal capital cost for energy capacity (low capital cost per added hour of duration) that is characteristic of many LDES technology types. Similarly, LDES can perform services that require shorter storage durations but might cost more per kilowatt of power capacity than a short-duration system.

It is important to perform a thorough cost-benefit analysis when considering the selection of an LDES technology to meet a desired use case. The need for longer LDES is growing, but the commercial availability of many LDES technologies is still nascent. In fact, some utilities are beginning to consider simply procuring longer-duration lithium-ion battery systems configured for 8-hour or even 12-hour durations. Lithium-ion battery technology is capable of performing this role; simply adding more battery modules that feed into an existing inverter would make it possible. However, doubling (or tripling) the duration of lithium-ion battery system almost doubles (or triples) the capital costs because there is little economy of scale for adding energy storage capacity (the marginal cost of adding duration is high, unlike many LDES technologies). LDES

technologies are expected to be lower cost at longer duration, but how much lower? And if not, will the added benefits of the longer duration outweigh the costs?

To answer these questions, it is critical to have high-quality data on the cost of LDES technologies. However, the public availability of LDES data is limited. In particular, more accurate depictions of costs, even at a high level, are difficult to ascertain without information from companies that are developing the LDES technologies.

Approach

To gain more insights into cost data for representative LDES technologies, the LDES Council issued a survey to its technology developer members requesting current high-level performance metrics and capital and operating and maintenance (O&M) costs for their preferred commercial project size in a power-to-power (P2P) or a power-to-heat (P2H) application, depending on the technology.

In addition to performance and cost data, the survey requested respondents to provide their technology's current technology readiness level (TRL). Performance and cost data were requested for two contract year bases – 2025 and 2030 – with the intent to have technologies at TRL 4 or 5 to provide expected 2030 costs and those at TRL 6 and above to provide 2025 costs. The year for the cost estimate is the date a project would be contracted, e.g., "notice to proceed" or "final investment decision." The expected 2030 costs are reported in 2025 dollars.

Data collected from the survey were reviewed and analysed, and the results have been aggregated and summarised in this report. The names of individual technology developers are not included given confidentiality restrictions. However, the data is presented in an aggregated format with related technologies included in several broad technology categories. This approach still results in actionable information regarding the current and expected cost, performance, and maturity of LDES technologies.

Actionable LDES Information for Industry Stakeholders

Understanding the performance and cost metrics of emerging LDES technologies is valuable to a wide range of stakeholders including investors, industrial energy users, policymakers, customers, and utilities or independent power producers. Potential benefits include:

- **Investors**
  - ***Risk Assessment and Return on Investment***: Metrics like round-trip efficiency (RTE) and capital cost help investors evaluate the financial viability and expected returns of LDES projects.

  - ***Technology Comparison***: Comparisons across technologies assist guiding investment toward the most promising options.
  - ***Market Timing***: Cost trends and performance improvements signal when a technology is ready for scale-up or commercialization.
  - ***Due Diligence***: Detailed performance and cost data support more informed decisions during mergers, acquisitions, or venture funding.
- **Industrial Energy Users (including data centres)**
  - ***Energy Resilience***: High-efficiency, cost-effective LDES can ensure uninterrupted power during outages or peak demand periods.
  - ***Cost Optimization***: Understanding capital and operating and maintenance costs helps in budgeting and reducing energy expenses.
  - ***Sustainability Goals***: Performance metrics help align with carbon reduction targets by integrating renewables with reliable storage.
  - ***Grid Independence***: Combining LDES with on-site power generation enables strategic planning for microgrids or behind-the-meter storage solutions.
- **Policymakers**
  - ***Informed Regulation***: Performance and cost data support the creation of incentives, subsidies, and standards that promote viable technologies.
  - ***Energy Planning***: Detailed LDES information helps in modeling future grid scenarios and planning for decarbonization pathways.
  - ***Public Spending Justification***: Transparent metrics justify public investments or grants in emerging technologies.
  - ***Equity and Access***: Cost data can inform policies that ensure equitable access to clean energy storage solutions.
- **Utilities**
  - ***Grid Reliability***: RTE and operational costs help utilities assess how LDES can support grid stability, frequency regulation, and peak shaving.
  - ***Rate Design***: Cost insights help utilities design tariffs that reflect the value of storage to the grid.
  - ***Technology Procurement***: Cost and performance information for LDES technologies facilitates competitive bidding and selection of storage technologies based on lifecycle cost and performance.

Utility Resource Planning

Electric utilities around the world routinely engage in structured, long-term planning to ensure they can meet future energy demand in a reliable, cost-effective, and

sustainable manner. This planning process typically spans a 10- to 20-year horizon and results in a comprehensive utility resource plan that outlines projected demand growth, resource requirements, and recommended investment strategies.

The utility resource plan serves as both a strategic roadmap for internal decision-making and, in many jurisdictions, a regulatory or policy submission. It helps utilities align infrastructure development with national or regional energy goals.

Key inputs to the planning process include:

- Forecasts of electricity demand and load growth
- Climate and weather variability
- Fuel and energy price projections
- Policy and regulatory mandates
- Cost, performance, and availability of generation and energy storage technologies

Utilities use these inputs to model multiple future scenarios, each reflecting different economic, technological, and policy conditions. The planning process often includes stakeholder engagement, regulatory consultation, and public input to ensure transparency and alignment with broader societal objectives.

To date, data availability for many emerging LDES technologies is still limited, constraining resource planning analyses. The cost survey described in this report can help mitigate this lack of information by providing detailed data on LDES technologies, enabling planners to assess their competitiveness and potential role and inclusion in future resource portfolios.

Key Information Point

The cost survey described in this report provides some of the data required for system planners to include emerging LDES technologies in their scenario modeling and planning efforts.

Utilities, system operators, and modelers interested in learning more about specific technologies included in this study may reach out to the LDES Council to be connected with relevant technology developers.

1. SURVEY DEVELOPMENT

EPRI and the LDES Council developed the survey that the LDES Council sent to a subset of its technology members. The survey was designed specifically to be informative about cost and high-level operational data. The survey requested the following data:

- **Capital and O&M Costs:** Costs broken down by category and subsystem, including contingency, storage system, charge system, discharge system, balance-of-plant (BOP), sitework, controls, and fixed and variable O&M costs
- **Project Size and Duration:** Information for a commercial-scale size of the energy storage system. If flexible, respondents were asked to use a 10-hour duration resource and a 100 MW discharge capacity.
- **Resource Characteristics:** Lifetime, RTE, storage capacity in MWh, charging and discharging capacities in MW, charge and discharge durations, degradation rate, and depth of discharge
- **TRL:** Developer's assessment of the current TRL of their technology

The full surveys, including instructions and item descriptions, are included in Appendix A.

2. TRL ASSESSMENT

Based on the assumption that organizations may use different criteria for assessing TRL, EPRI independently assessed the TRL for the technologies in the LDES Council's survey scope based on a documented set of criteria that was originally developed by the National Aeronautics and Space Administration and adapted by EPRI to assess the readiness and track the development of energy storage technologies [2]. EPRI's TRL criteria are included in Appendix B and consists of the following nine TRLs:

1. TRL-1 Basic Principles Observed and Reported
2. TRL-2 Formulation of the Application
3. TRL-3 Proof-of-Concept
4. TRL-4 Component Validation in a Laboratory Environment
5. TRL-5 Component Validation – Pertinent Technology Components are Validated in a Relevant Environment
6. TRL-6 Process Development Unit – Consists of Prototype Components in a Relevant Environment
7. TRL-7 Pilot Plant – Integrated, Fully Functional Prototype that Incorporates All of the Features of the Anticipated Full-Scale Deployment in an Operational Environment
8. TRL-8 Commercial Pilot Plant – Deployment of the Technology in Its Final Form and Under Expected Conditions
9. TRL-9 Commercial Plant – Normal Commercial Service

3. DATA COLLECTION AND REVIEW

Data Collection

The LDES Council was responsible for sending the survey to and collecting completed surveys from its members. The completed surveys were provided to EPRI, limited to the team supporting the study, to review and analyse the submitted data.

Data Review

All the surveys were reviewed to ensure the submitted data aligned with values that have already been collected independently through other means or with common industry practice, e.g., application of cost contingencies.

TRL Assessment

EPRI compared the developers' reported TRL with its own independent assessments. During the interviews between the LDES Council, EPRI, and the survey respondents, differences in TRL assessments by EPRI and respondents were discussed, where each shared the supporting documentation or bases that were used to determine the TRL. In all cases, the respondents agreed to use EPRI's TRL criteria and assessment, so that all technologies were evaluated on a consistent basis, improving comparability across different technologies.

Cost Information

Capital Costs

It is important to clearly define what is included in the reported capital cost of a given LDES technology used in this report. This study follows the United States Department of Energy's National Energy Technology Laboratory (NETL) definitions for capital costs [3]. The survey reports capital costs using total plant costs (TPC) or capital expenditure (CAPEX). TPC comprises the cost of delivered process equipment, on-site facilities, and infrastructure that support the plant (e.g., shops, offices, labs, roads), and the direct and indirect labour required for its construction and/or installation plus the cost of engineering, procurement, and construction services and contingencies. Respondents were requested to provide costs using the cost structure provided, i.e., TPC, contingency, and six subsystem costs. In many cases, the respondents provided costs using the suggested breakdown, but there were a few cases where only a TPC value or a few subsystem costs were provided, limiting the capital cost analysis to a TPC basis. Contingencies were also reviewed to ensure that the values provided were

commensurate with each technology developer's certainty level of the cost estimate or level of commercial project design definition. AACE cost estimating guidelines [4] were shared with the developers for typical contingency values.

Respondents were asked to provide the certainty level (i.e., low, medium, or high) of their cost estimate. The majority of the cost estimates were provided with a medium cost certainty level, which respondents clarified were about an AACE Class 4 to 5 accuracy. In other words, the majority of the estimates had a level of project definition in the range of 1–15% and expected accuracy ranges from -50% to +100% for AACE Class 5 estimates and from -30% to +50% for AACE Class 4 estimates. In a few cases, respondents provided a higher certainty level for their estimates, noting that the level of detail in project design was more defined. These high certainty level cost estimates would be more in line with AACE Class 3 and expected accuracy from -20% to +30%.

O&M Costs

In addition to capital costs, respondents were requested to provide estimates of fixed and variable O&M costs for their proposed commercial designs. Annual fixed O&M costs include operating labour and scheduled maintenance. Variable O&M costs generally encompass unscheduled maintenance and any consumables. In some cases, respondents provided only a single cost, which was intended to represent the total annual O&M costs, including both fixed and variable costs.

Since there was an inconsistency with how respondents provided fixed and variable O&M costs, assessments were made on a total annual cost basis that included both fixed and variable O&M costs. In many cases, respondents provided an estimate based on a percentage of TPC. For those who provided both fixed and variable O&M cost components, a 40% capacity factor was assumed to translate the variable O&M cost to an annual cost.

Resource Characteristics

The data were reviewed to ensure that the values for RTE, capacities, and durations provided aligned with how the parameters were defined. After clarifying the definitions of the parameters, some of the developers resubmitted their resource characteristic data.

4. DATA ANALYSIS

Technology Categorization

Maintaining the anonymity of the respondents was a key objective of the study, so the surveys were reviewed to ensure data sufficiency and to determine how best to group the technologies and aggregate the data. Based on the energy storage technology types and the limited sample size of the submitted surveys, five broad categories were identified, which represented the highest level of similarity and cost compatibility between technologies within a group. Each technology was placed into only one of the following categories:

1. Intraday Electrochemical Energy Storage
2. Intraday Compressed Gas Energy Storage
3. Intraday Pumped Heat Energy Storage
4. Multi-Day Energy Storage
5. Thermal Energy Storage (TES)

The technologies included in each category are discussed in detail below. Aggregating the data in this manner respects the commercially sensitive nature of the information by avoiding the disclosure of the data of a specific technology.

Intraday Electrochemical Energy Storage

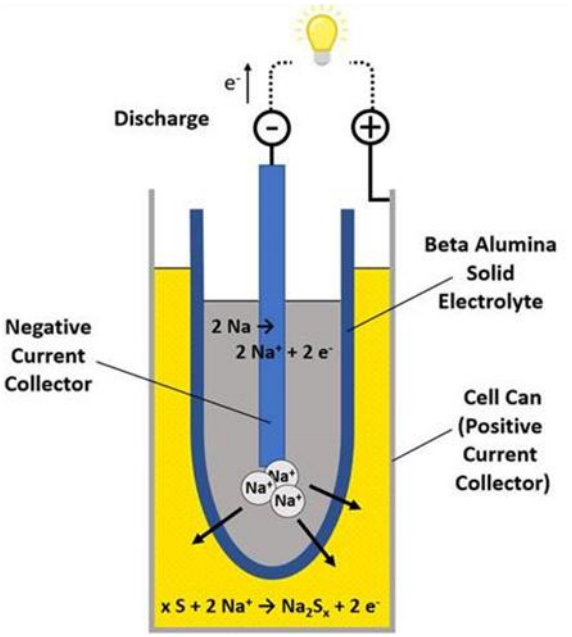
Intraday Electrochemical Energy Storage technologies store electricity in advanced chemistry batteries. The battery cell is structured to allow ions to flow through the electrolyte or a porous member, which is electrically insulating, to deliver energy to an external circuit. Charging the batteries with electricity causes the ions to flow to a higher energy state and discharging causes ions to flow to a lower energy state.

The types of technologies in this category include sodium-sulphur (NaS), vanadium redox flow batteries (VRBs), and iron-salt flow batteries. The technical aspects of these technologies are discussed in more detail below.

Sodium-Sulphur Batteries

A traditional NaS cell, depicted in Figure 6, operates at about 570°F (300°C) because sodium and sulphur are solid and unreactive at room temperature. The molten sodium in the centre of the cell is the negative electrode of the cell. The beta-alumina solid electrolyte (blue) separates the negative (grey) and positive (yellow) electrodes and acts as the ionic conductor between the electrodes. During discharge, sodium is oxidized,

losing one electron that migrates across the ceramic solid electrolyte, where it combines with sulphur anions to form sodium polysulfide. Acceptable battery performance at moderate temperatures of 212–318°F (100–150°C) can be achieved with an improved electrolyte.

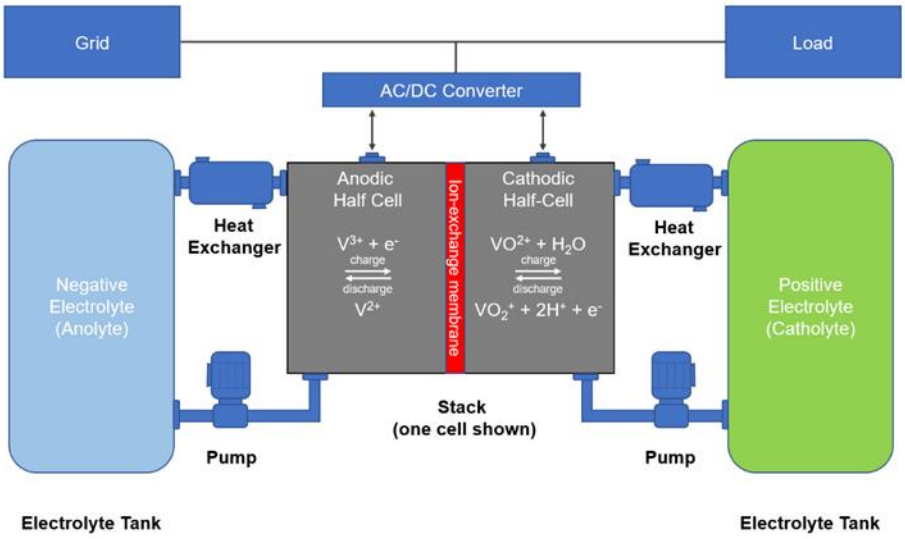


Source: EPRI

Figure 6. Simplified diagram of a NaS battery cell

Vanadium Redox Flow Batteries

Redox flow batteries are secondary batteries that provide modular and scalable energy storage systems for a variety of applications such as grid support, renewables integration, or backup in remote or isolated locations. The VRB is a type of redox flow battery that employs two types of vanadium ion pairs to store and dispatch electrical energy. All active components are soluble in the electrolyte. Figure 7 illustrates the main components of a VRB. The VRB contains two tanks of vanadium electrolytes in various oxidation states. The anolyte (negative electrolyte) tank contains reduced vanadium ions while the catholyte (positive electrolyte) tank contains oxidized vanadium ions. The battery works by pumping the liquid anolyte and catholyte into adjacent half-cells. A large volume of liquid is required because of the low concentration of vanadium, so VRBs have a low energy density and high footprint. The electrolyte storage system consists of tanks for the negative electrolyte (anolyte) and the positive electrolyte (catholyte), a pump for each tank, and associated piping. The entire system is contained within an enclosure.



Source: EPRI

Figure 7. Diagram of a VRB

Iron-Salt Batteries

Iron-salt batteries operate on the same principles as conventional ZEBRA batteries, a type of rechargeable molten-salt battery based on commonly available and low-cost materials, which have been utilized for over 40 years in sectors such as electric vehicles, industrial applications, and telecom backup. This battery replaces the traditional nickel cathode with iron chloride ($FeCl_2$), reducing material costs and making it more suitable for grid-scale energy storage applications, particularly for LDES. The use of iron instead of nickel not only lowers overall system costs but also enhances the viability of this technology for energy storage needs as it is readily available.

Resource Characteristics

Key Information Point

For each technology category, resource characteristics are reported in a range from low CAPEX to high CAPEX. Characteristics under each of the low and high CAPEX columns in the tables that follow are based on the one technology in the category that represents either the low or high CAPEX data point, so that all parameters under each column range are based on a single technology.

The ranges in footprint, resource lifetime, RTE, and storage capacity degradation for the Intraday Electrochemical Energy Storage technologies in this study are presented in Table 1.

Table 1. Resource characteristics for Intraday Electrochemical Energy Storage technologies

Parameter	2025		2030	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
Footprint, MWh/acre	444	100	400	100
Resource Lifetime, yr	20	25	25	25
RTE*, %	85	70	65	75
Storage Capacity Degradation, %/yr	0.99	0.00	0.10	0.00
* Note that sample size for 2030 included a different mix of technologies, resulting in the different range in RTE.				

Intraday Compressed Gas Energy Storage

Intraday Compressed Gas Energy Storage technologies in this category compress gas, either air or CO_2, and store it as potential energy. When electrical energy is needed, the compressed fluid is heated and expanded to drive a turbine-generator.

Compressed air can either be stored below ground in a geologic storage reservoir or above ground in insulated vessels as a cryogenic liquid. Air that is stored below ground uses an advanced process that captures and stores the heat of compression, which is used in the discharge process to heat and expand the air as it drives a turbine. Air that is stored above ground is refrigerated to cryogenic temperatures for compact storage at modest elevated pressure rather than in high-pressure underground geologic formations. Cryogenic and above ground energy storage allows for greater siting flexibility and the ability to heat-integrate hot or cold thermal sources for high efficiency.

Technologies that use CO_2 are analogous to the closed-loop, advanced compressed air energy storage system but with CO_2 instead of air as the storage medium and working fluid. CO_2 has favourable physical and thermodynamic properties that allow its use in both gaseous and liquid phases at ambient temperature, reducing the energy requirements to raise its pressure and allowing for efficient heat transfer and storage above ground with compact equipment. The heat of CO_2 compression during charging is captured in a TES system for subsequent return to the CO_2 upon discharge, which boosts power output.

Compressed Gas

Distinguishing characteristics of Compressed Gas Energy Storage technologies include the following:

- **Use of Compressed Gas as Storage Medium:** Air or CO_2 gas is typically utilised as the working fluid. These fluids are selected based on differing sets of characteristics, which can include abundance, cost, non-toxicity, and thermodynamic properties that enable efficient energy conversion.
- **Thermodynamic Diversity:** Compressed Gas Energy Storage technologies can operate under different types of thermodynamic principles:
  - **Adiabatic:** Heat from the compression is captured and reused to heat the compressed gas during discharge
  - **Diabatic:** Heat from the compression is rejected and external fuel is used as heat during discharge
  - **Isothermal:** Compression and expansion steps occur at nearly constant temperature using cooling mechanisms
- **Flexible Storage Configurations:** The compressed fluids can be stored in several types of containers including underground salt caverns, above-ground pressure vessels, repurposed pipelines, or hybrid systems with hydrostatic compensation. Systems that do not use air need on-site containment of the low-pressure, discharged gas, too.
- **Synchronous Power Generation:** Most compressed gas systems use rotating machinery (e.g., compressors and expanders) that can provide valuable grid services such as rotating inertia
- **Renewable Integration:** These systems are well suited for intermittent renewable energy integration, enabling energy shifting and balancing over long durations

For the following process description, air is assumed to be the working fluid. In charge mode, the system stores energy by compressing air and storing it under high pressure.

Charge

- During periods of low electricity demand or surplus renewable generation, electricity is used to power compressors
- Air is compressed to high pressures and stored in some container.
- In adiabatic systems, heat generated during compression is captured with TES
- In diabatic systems, this heat is rejected
- Isothermal systems use cooling mechanisms to maintain constant temperature during compression

Storage

- Effective containment of high-pressure air is important to minimize losses due to leaks
- Thus, compressed air is stored in underground caverns, high-pressure tanks, or repurposed pipelines. Some systems use hydrostatic compensation or water pistons to maintain pressure.
- Maintaining pressure with hydrostatic compensation allows a system to utilise a container's volume to more effectively store air at constant pressure
- In adiabatic systems, the thermal energy from compression is stored separately in TES units using sand, gravel, or other media such as hot water tanks

Discharge

- When electricity is demanded, the compressed air is released, heated, and expanded through turbines or engines
- The pressure energy is converted into kinetic energy, which drives mechanical components connected to a generator, thus, effectively converting the stored potential energy into electricity

Resource Characteristics

The ranges in footprint, resource lifetime, RTE, and storage capacity degradation for the Intraday Compressed Gas Energy Storage technologies are presented in Table 2.

Table 2. Resource characteristics for Intraday Compressed Gas Energy Storage technologies

Parameter	2025		2030	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
Footprint, MWh/acre	16	95	16	95
Resource Lifetime, yr	30	35	30	35
RTE[‡], %	72	53	72	57
Storage Capacity Degradation, %/yr	Assumed negligible.			

Intraday Pumped Heat Energy Storage

Pumped Heat Energy Storage (PHES) systems store electricity by converting it into thermal energy using a heat pump and later convert that thermal energy back into electricity using a heat engine. The system typically consists of two thermal reservoirs—one hot and one cold—where energy is stored in low-cost, durable materials. Distinguishing characteristics of PHES systems include:

- **Distinct Thermal Storage Tanks, One Hot, the Other Colder:** PHES uniquely deploys electrically driven heat pumps to transfer heat into a hot reservoir (and extract it from a cold reservoir) during charging and then utilises the resulting temperature differential to power a heat engine that generates electricity during discharge
- **PHES Designs:** PHES designs vary in their thermodynamic cycle configurations, ranging from Brayton to Rankine cycles, depending on goals like efficiency, temperature levels, and system integration
- **Reversible Energy Storage:** PHES enables electricity-to-heat and heat-to-electricity conversion using integrated cycles
- **Working Fluids:** Working fluids are in mostly closed-loop circulation, reducing costs and storage needs

The following is a general process description of PHES:

Charge

- Electricity input powers a heat pump or compressor, which extracts heat from a cold thermal reservoir and transfers it to a hot reservoir
- The hot tank stores sensible heat, while the cold tank stores cold energy
- There may be the presence of intermediate warm tanks in some configurations to improve efficiency

Storage

- Stored energy remains in the hot and cold thermal stores until needed
- Materials such as crushed rock, concrete, or other sensible-heat media allow for scalable, durable storage with minimal degradation

Discharge

- The temperature difference between the hot and cold tanks drives a heat engine or expander, converting thermal energy back into electricity

Resource Characteristics

The ranges in resource footprint, lifetime, RTE, and storage capacity degradation for the Intraday PHES technologies are presented in Table 3. Insufficient 2025 data were received from the survey so only 2030 data are reported.

Table 3. Resource characteristics for Intraday PHES technologies in P2P configuration

Parameter	2030	
	Low CAPEX	High CAPEX
Footprint, MWh/acre	74	218
Resource Lifetime, yr	30	60
RTE, %	57	62
Storage Capacity Degradation, %/yr	0.20	0.01

Multi-Day Energy Storage

Multi-Day Energy Storage is defined by the use case rather than by similar technology types. This category includes commercial and emerging technologies capable of 100 hours or more of storage, spanning chemical (e.g., E-fuels, reversible fuel cells, thermochemical), electrochemical (e.g., flow, metal-air), and mechanical (e.g., compressed gas, geomechanical, liquid air) types, along with certain advanced thermal and pumped-heat systems. E-fuels, reversible fuel cells, thermochemical, and geomechanical storage types are discussed below. The other technology types are discussed in other sections. Because this category spans multiple physics, cost ranges provided in the *Cost Data Aggregated Results* section reflect both technology diversity and duration effects.

E-Fuels

E-fuels (also known as electro fuels) are chemical energy carriers synthesized with electrically driven processes that combine carbon and hydrogen sources into molecules chemically similar to traditional fossil-fuel hydrocarbons. These fuels store energy chemically and release it through combustion or electrochemical reactions.

Reversible Fuel Cells

Reversible fuel cells are capable of generating electricity from a fuel such as hydrogen or hydrocarbon and also running in the reverse direction to synthesize the fuel using an electrical energy input. Variations of this technology include proton exchange membrane and solid oxide fuel cell types.

Thermochemical

Thermochemical storage technologies combine aspects of thermal energy storage with reversible chemical reactions. Typical reactions used for this technology can be controlled with temperature; heating the storage media drives the reaction in the forward

direction, storing chemical energy. Subsequently passing a reactant over the charged storage media can release the chemical energy. The energy is absorbed or released during the breaking or forming of chemical bonds.

Geomechanical

Geomechanical technologies use underground rock formations to store energy by mechanically deforming them (e.g., pushing rock plates apart or compressing them). Energy is recovered by allowing the rock to return to its original state, driving mechanical systems or turbines. Their primary advantage is the utilisation of natural geological formations for low-cost storage media.

Resource Characteristics

The ranges in resource footprint, lifetime, RTE, and storage capacity degradation for the Multi-Day Energy Storage technologies are presented in Table 4. Insufficient 2025 data, i.e., from developers with technologies at TRL 6 and above, were received from the survey, so only 2030 data are reported.

Table 4. Resource characteristics for Multi-Day Energy Storage technologies

Parameter	2030	
	Low CAPEX	High CAPEX
Footprint, MWh/acre	2,041	75
Resource Lifetime, yr	30	40
RTE, %	70	50
Storage Capacity Degradation, %/yr	Assumed negligible.	

Thermal Energy Storage

TES technologies capture thermal energy in an appropriate medium, where either sensible heat or latent heat is stored. The stored heat can then be utilised by a process for industrial use or a power cycle to generate power.

The technologies that store sensible heat in this category are capable of storing heat at temperatures up to 3632°F (2000°C), while the technologies that store latent heat can store heat at temperatures up to 2552°F (1400°C). Overall, latent heat systems typically provide a higher energy density than sensible heat systems. Although many of the technologies can be integrated with a power cycle, all technologies in this category have proposed to deliver heat for P2H applications.

Sensible Heat Thermal Energy Storage

Distinguishing characteristics of sensible heat technologies include the following:

- **Temperature-Based Energy Retention**: Stores energy by increasing the temperature of a solid or liquid medium without changing its phase. The energy is retained as internal thermal energy and released by cooling the medium. This contrasts with latent heat systems, which rely on phase changes (e.g., melting) for energy storage.
- **Use of Inert, Durable Materials**: Common storage media include ceramic bricks, carbon blocks, concrete, slag pellets, sand, crushed rock, and molten salt. These materials are chemically stable, non-toxic, and capable of withstanding extreme temperatures.
- **Low-Temperature Operation**: Some systems operate below 1112°F (600°C), making them suitable for industrial heat, district heating, and integration with fossil or renewable power plants.
- **High-Temperature Operation**: High-temperature systems operate at temperatures above 3632°F (2000°C), making them suitable for industrial processes such as cement, steel, and chemical production.
- **Dual Use: Heat and Power**: Many systems can discharge energy as either heat (for industrial use) or electricity. This flexibility supports both decarbonization of heat and grid balancing.
- **Long Lifespan and Reusability**: These systems can cycle thousands of times without significant degradation, enabling lifespans exceeding 20–30 years. Many of the materials in this category are recyclable at end-of-life.

The following is a general process description of sensible heat energy storage:

Charge:

- Heat is introduced via electric resistance heaters, gas, steam, or hot air. The thermal medium absorbs and stores the heat. Charging can be powered by grid electricity, renewables, or waste heat.

Storage:

- Energy is retained in the thermal medium with minimal degradation, and systems are insulated to reduce standby losses (typically <2% per day). Storage durations range from 4 to 24 hours, with some systems targeting multi-day storage.

Discharge:

- Heat transfer fluids such as air or steam are circulated through the hot media to absorb and deliver the thermal energy. Output can be steam, hot water, hot air, or electricity via turbines, thermophotovoltaic cells, or other heat engines. Discharge rates and temperatures vary by system design and application.

Phase-Change Materials Energy Storage

Distinguishing characteristics of phase-change materials (PCM) include the following:

- **Latent Heat Storage:** PCMs store energy through latent heat during phase transitions, offering high energy density and consistent temperature during energy absorption or release, particularly important for steam generation
- **High-Temperature Operation:** PCMs have been designed for TES to operate from 392°F to 2552°F (200–1400°C), making them suitable for a wide range of applications in industrial heating and power generation
- **Material Diversity:** PCMs are categorized as organic (e.g., paraffins, fatty acids), inorganic (e.g., salt hydrates, metals), and eutectic mixtures
- **Cycling Stability:** PCMs can generally retain their properties and have minimal degradation over many thermal cycles

The following is a general process description of PCM energy storage:

Charge

- Heat is supplied via resistance heaters, steam, or solar thermal collectors
- This heat is then transferred to the PCM through direct contact with a heat transfer fluid (HTF) or indirectly through embedded tubing
- While the PCM approaches its melting temperature, it absorbs latent heat and phase transition occurs
- The temperature during this phase change remains nearly constant

Storage

- Energy is stored as both latent heat (during the phase change) and sensible heat (before and after the phase change) in the PCM
- Storage vessels or blocks are insulated and pressure-managed to minimize heat loss and maintain system integrity

Discharge

- Heat is extracted from the PCM via the HTF or steam tubes

- This thermal energy can be converted to electricity via Stirling engines, carbon dioxide (CO_2) power cycles, turbines, or steam cycles
- Heat transfer during discharge is primarily conductive

Resource Characteristics

The ranges in footprint, resource lifetime, RTE, and storage capacity degradation for the TES technologies are presented in Table 5. Note that the RTE metric is defined as thermal energy delivered during discharge, divided by the electrical energy consumed during charge (as is emblematic of a P2H configuration).

Table 5. Resource characteristics for TES technologies

Parameter	2025		2030	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
Footprint, MWh_{th}/acre	1,650	1,786	1,650	1,786
Resource Lifetime, yr	30	20	30	20
RTE (P2H), %	97	95	97	95
Storage Capacity Degradation, %/yr	0.10	0.99	0.10	0.99

Data Normalisation

In general, respondents based their surveys on their preferred commercial size, and only a few had selected the loosely suggested project size with 100 MW discharge capacity and 10-hour duration. This resulted in a wide range for both charge and discharge durations and capacities, presenting a challenge to compare data in an aggregated manner.

Normalising Costs to a Common Design Basis

To compare the technologies within a technology category on a common basis, some of the technologies were scaled in size to have the same charge, storage, and discharge capacities and discharge duration. When scaling a technology to a different size, it was assumed that the RTE is unchanged, allowing the charge duration variable to float. The scaled sizes for each technology group are presented in Table 6, and the methodology for applying the cost scaling is included in Appendix C.

Table 6. Scaled sizes for technology categories

Technology Category	Charge Capacity	Storage Capacity	Discharge Capacity	Discharge Duration
Intraday Electrochemical Energy Storage	100 MW	1,000 MWh	100 MW	10 h
Intraday Compressed Gas Energy Storage	100 MW	1,000 MWh	100 MW	10 h
Intraday PHES	200 MW*	1,000 MWh	100 MW	10 h
Multi-Day Energy Storage	20 MW*	1,000 MWh	10 MW	100 h
TES	50 MW*	500 MWh_{th}	25 MW_{th}	20 h

** Selected to preserve the average ratio of 2:1 for the charge-to-discharge capacity.*

Normalising Costs to a Common Location

Respondents were also asked to provide the nominal location that represented a favourable project site for their design as well as the basis for their cost estimate. About one-third of the cost data were based in a non-U.S. location, while the remainder were based in several locations in the U.S.

Consideration was given to normalise the capital and O&M costs to a common U.S. location and to present costs both before and after normalisation. “Location factors” from known industry references, including the 2023 Richardson International Cost Factors [5], 2023 Compass Global Construction Cost Yearbook [6], and the 2025 Arcadis International Construction Costs [7] were reviewed, and it was determined that there is some variability in the international cost factor data between the references. For consistency in the normalisation of costs, only a single reference, Richardson, was used for the international cost factors. Both its U.S. and International tables were normalised to “Richardson USA,” so they are on the same basis. Further, data from the U.S. tables were used to estimate factors for a “U.S. Lower 48” nominal location, which was used as the common location basis. Richardson’s Overall Location Cost Factors were used to normalise capital costs. However, to normalise O&M costs, Richardson’s labour indexes and bulk material indexes were used to adjust the fixed and variable O&M costs, respectively.

Cost Data Aggregated Results

Normalised data were aggregated by technology categories to avoid disclosing individual company costs. Cost data are presented on a TPC basis in both total cost ($) and unit cost $/kWh. To increase the practical utility of the benchmarking, a breakdown

of TPC into charge, storage, and discharge subsystem cost components is also provided and defined as follows:

- **Charge Cost**: charge cost component / charge capacity with units in $/kW
- **Storage Cost**: storage cost component / storage capacity with units in $/kWh for P2P applications and $/kWh$_{th}$ for P2H applications
- **Discharge Cost**: discharge cost component / discharge capacity with units in $/kW for P2P applications and $/kW$_{th}$ for P2H applications

The levelised cost of storage (LCOS) is a commonly used metric for energy storage technologies, however, it is more appropriate for energy storage systems with use cases focused on delivering energy (kWh) that are often cycled frequently under well-defined operating profiles. For example, an energy storage system paired with a solar energy project may often charge in the middle of the day and discharge in the evening to meet peak loads. However, a use case more oriented toward power (kW), such as providing system capacity or backup power, may cycle infrequently and would result in a misleadingly high LCOS value.

A 100 MW, 40-hour LDES system, for instance, may discharge only a handful of times per year by design, primarily during extended grid stress events such as multi-day weather impacts, fuel supply disruptions, or transmission outages. In those circumstances, the LDES system's value is not driven by the total amount of energy it delivers over the year, but by its ability to sustain output over long durations when shorter duration resources are exhausted. An LCOS calculation, which divides annual costs by annual energy delivered, would therefore assign a very high cost to such an asset because of its low utilisation, even though the same asset could meaningfully reduce loss of load, avoid costly emergency actions, or substitute for firm generation capacity. As a result, an LCOS comparison can materially undervalue the economic and system benefits of LDES for reliability- and resilience-oriented use cases.

Furthermore, LCOS is highly sensitive to assumptions regarding utilisation, dispatch frequency, financing, and asset lifetime, which vary widely across technologies and applications. Accordingly, this study prioritizes Total Plant Cost (TPC) (or more broadly, capital expenditure or CAPEX) as the primary benchmarking metric, as it more directly captures capital intensity and enables more transparent, technology-agnostic comparisons. TPC is particularly relevant for LDES systems because it better reflects the strategic role these assets play in system planning and grid reliability. When complemented with O&M costs and key performance parameters such as asset life and RTE, TPC information provides robust inputs for cost-benefit and system-level analyses. TPC can then be used by system planners, modelers, utilities and other stakeholders to assess the value of long duration energy storage in the context of the specific use cases and system needs they have identified.

For each technology category, aggregated cost data are reported in a range from low CAPEX to high CAPEX. Cost data under each of the low and high CAPEX columns in the tables that follow are based on the one technology in the category that represents either the low or high CAPEX data point, so that all cost parameters under each column range are based on a single technology.

Key Cost Point

Charge, storage, and discharge subsystem costs and total annual O&M costs in the aggregated cost data tables align with the technology represented by the data point and could show high costs for a technology with the low CAPEX and vice versa.

For the Intraday Electrochemical, Intraday Compressed Gas, and TES and Energy Storage categories, data were aggregated for contract years 2025 and 2030. For the Intraday PHES and Multi-Day categories, data were aggregated for contract year 2030 only. Of the five categories, only the TES technologies have provided P2H data, while the other four provided P2P data. Note the aggregated 2030 cost data are reported in 2025 dollars.

Intraday Electrochemical Energy Storage

All the Intraday Electrochemical Energy Storage technologies have been scaled to have the following performance characteristics:

- **Charge Capacity:** 100 MW
- **Storage Capacity:** 1000 MWh
- **Discharge Capacity:** 100 MW
- **Discharge Duration:** 10 h

The aggregated capital and O&M cost data for contract years 2025 and 2030 are presented in Table 7 and Table 8, respectively, and a chart comparing 2025 and 2030 TPC ranges in $/kWh is shown in Figure 8. Note that the Intraday Electrochemical technologies that make up the 2030 group are not the same as those in 2025, i.e., some developers only provided 2025 costs, some both 2025 and 2030 costs, and some only 2030 costs.

Table 7. Aggregated 2025 cost data for Intraday Electrochemical Energy Storage category

Parameter	Reference/Nominal Location		U.S. Lower 48 Location	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
TPC, $	220,252,000	491,832,000	220,252,000	572,003,000
TPC, $/kW	2,203	4,918	2,203	5,720
TPC, $/kWh	220	492	220	572
Charge Cost, $/kW	305	286	305	333
Storage Cost, $/kWh	159	436	159	507
Discharge Cost, $/kW	305	269	305	313
Total Annual O&M Cost, % of TPC	1.49	0.21	1.49	0.39

Table 8. Aggregated 2030 cost data for Intraday Electrochemical Energy Storage category

Parameter	Reference/Nominal Location		U.S. Lower 48 Location	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
TPC, $	210,009,000	307,674,000	244,241,000	357,826,000
TPC, $/kW	2,100	3,077	2,442	3,578
TPC, $/kWh	210	308	244	358
Charge Cost, $/kW	705	221	819	257
Storage Cost, $/kWh	69	265	80	308
Discharge Cost, $/kW	705	209	819	243
Total Annual O&M Cost, % of TPC	1.83	0.15	3.34	0.28

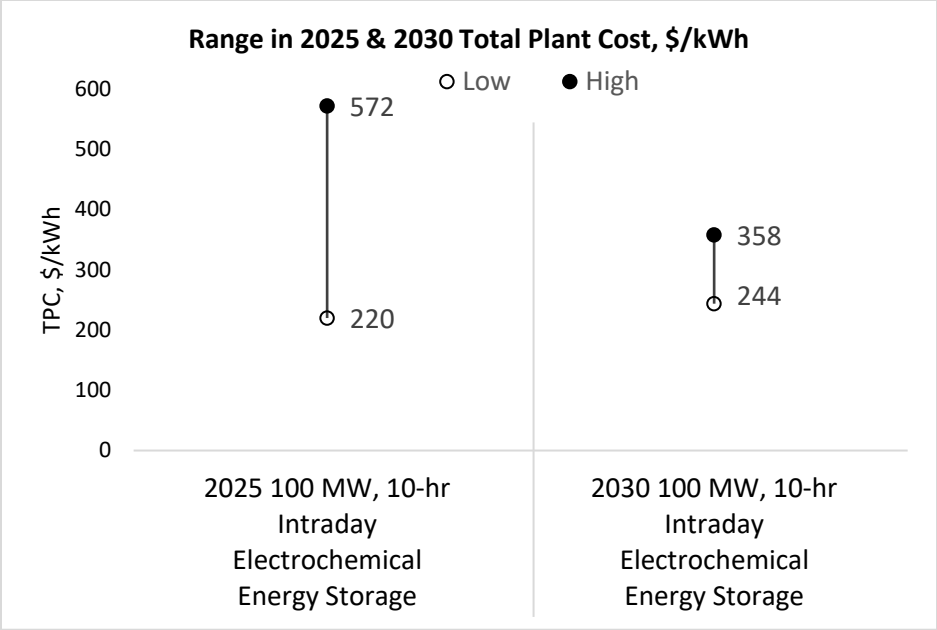


Figure 8. Range in 2025 and 2030 TPC in $/kWh for Intraday Electrochemical Energy Storage category

Observations

- The range of TPC in 2025 ($220 to $572/kWh) varies from lower than lithium-ion batteries (approximately $385/kWh [8] for a 100 MW-4-hr system that includes 15–20% overbuild) to somewhat higher. The advantage of LDES vs. lithium-ion batteries would have to be captured in a complete cost-benefit analysis that properly accounts for the value of additional duration.
- The range of TPC in 2030 ($244 to $358/kWh) is tighter than 2025 ($220 to $572/kWh). This suggests that disparate technologies may expect to achieve similarly lower costs, albeit via different methods.
- Conversely the range of O&M cost in 2030 is broader than in 2025. This suggests that staffing and maintenance schedules for future technology plant designs are not yet well-defined.

Based on the submitted cost data, the projected TPC cost reduction from 2025 to 2030 for the Intraday Electrochemical Energy Storage category averages ~37%.

Intraday Compressed Gas Energy Storage

All the Intraday Compressed Gas Energy Storage technologies have been scaled to have the following performance characteristics:

- **Charge Capacity:** 100 MW
- **Storage Capacity:** 1000 MWh

- **Discharge Capacity:** 100 MW
- **Discharge Duration:** 10 h

The aggregated capital and O&M cost data for contract years 2025 and 2030 are presented in Table 9 and Table 10, respectively, and a chart comparing 2025 and 2030 TPC ranges in $/kWh is shown in Figure 9.

Table 9. Aggregated 2025 cost data for Intraday Compressed Gas Energy Storage category

Parameter	Reference/Nominal Location		U.S. Lower 48 Location	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
TPC, $	135,663,000	470,851,000	157,777,000	470,851,000
TPC, $/kW	1,357	4,709	1,578	4,709
TPC, $/kWh	136	471	158	471
Charge Cost, $/kW	281	1,781	327	1,781
Storage Cost, $/kWh	83	166	96	166
Discharge Cost, $/kW	246	1,272	286	1,272
Total Annual O&M Cost, % of TPC	1.09	1.11	1.83	1.11

Table 10. Aggregated 2030 cost data for Intraday Compressed Gas Energy Storage category

Parameter	Reference/Nominal Location		U.S. Lower 48 Location	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
TPC, $	101,546,000	444,932,000	118,100,000	444,932,000
TPC, $/kW	1,015	4,449	1,181	4,449
TPC, $/kWh	102	445	118	445
Charge Cost, $/kW	215	1,683	250	1,683
Storage Cost, $/kWh	60	156	69	156
Discharge Cost, $/kW	204	1,202	237	1,202
Total Annual O&M Cost, % of TPC	1.24	1.11	2.08	1.11

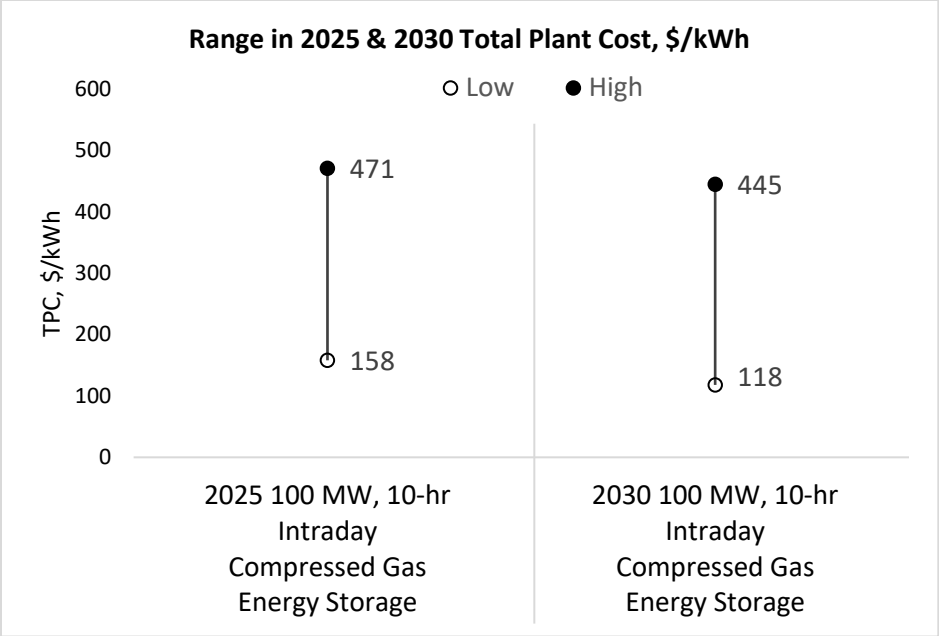


Figure 9. Range in 2025 and 2030 TPC in $/kWh for Intraday Compressed Gas Energy Storage category

Observations

- Similar to Intraday Electrochemical, the range of TPC in 2025 varies from substantially lower than lithium-ion batteries to higher. Economic viability will depend on the outcome of a full cost-benefit analysis.

Based on the submitted cost data, the projected TPC cost reductions from 2025 to 2030 for the Compressed Gas Energy Storage category range from 6-25%.

Intraday Pumped Heat Energy Storage

All the Intraday PHES technologies have been scaled to have the following performance characteristics:

- **Charge Capacity:** 200 MW
- **Storage Capacity:** 1000 MWh
- **Discharge Capacity:** 100 MW
- **Discharge Duration:** 10 h

The aggregated capital and O&M cost data for contract year 2030 are presented in Table 11, and a chart plotting the 2030 TPC range in $/kWh is shown in Figure 10.

Table 11. Aggregated 2030 cost data for Intraday PHES category

Parameter	Reference/Nominal Location		U.S. Lower 48 Location	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
TPC, $	290,309,000	338,428,000	235,525,000	338,428,000
TPC, $/kW	2,903	3,384	2,355	3,384
TPC, $/kWh	290	338	236	338
Charge Cost, $/kW	685	682	556	682
Storage Cost, $/kWh	77	106	63	106
Discharge Cost, $/kW	762	958	618	958
Total Annual O&M Cost, % of TPC	0.82	0.83	0.69	0.83

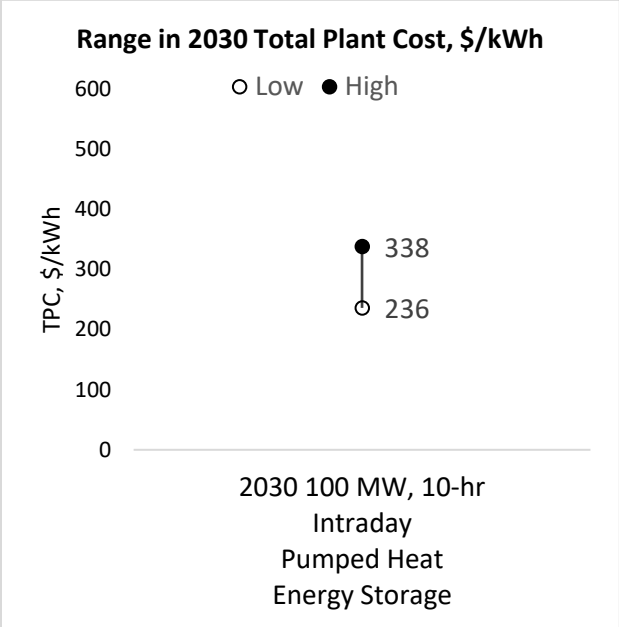


Figure 10. Range in 2030 TPC in $/kWh for Intraday PHES category

Observations

- The range of TPC reported for 2030 is fairly narrow, suggesting that the technologies included in this category may have a similar cost structure despite different design variations
- Insufficient 2025 data were received from the survey, so only 2030 data are reported

Multi-Day Energy Storage

All the Multi-Day Energy Storage technologies have been scaled to have the following performance characteristics:

- **Charge Capacity:** 20 MW
- **Storage Capacity:** 1000 MWh
- **Discharge Capacity:** 10 MW
- **Discharge Duration:** 100 h

The aggregated capital and O&M cost data for contract year 2030 are presented in Table 12, and a chart plotting the 2030 TPC range in $/kWh is shown in Figure 11.

Table 12. Aggregated 2030 cost data for Multi-Day Energy Storage category

Parameter	Reference/Nominal Location		US Lower 48 Location	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
TPC, $	26,413,000	33,243,000	26,413,000	37,960,000
TPC, $/kW	2,641	3,324	2,641	3,796
TPC, $/kWh	26	33	26	38
Charge Cost, $/kW	217	1,000	217	1,142
Storage Cost, $/kWh	20	3	20	3
Discharge Cost, $/kW	208	1,040	208	1,188
Total Annual O&M Cost, % of TPC	2.69	8.25	2.69	1.65

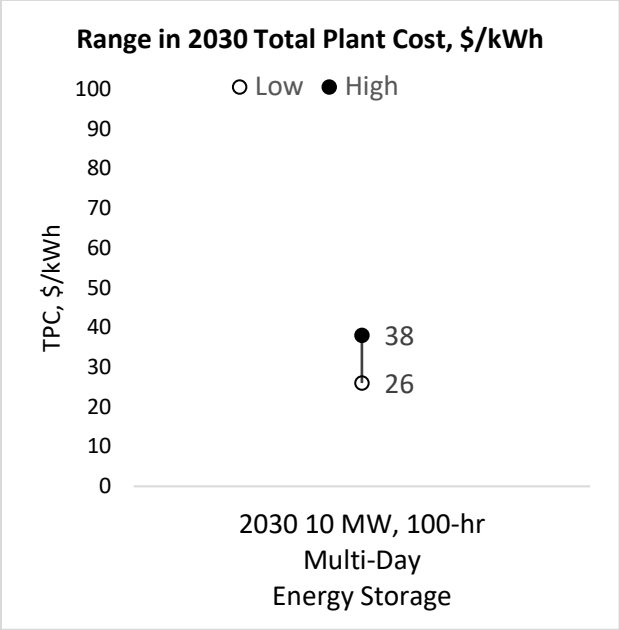


Figure 11. Range in 2030 TPC in $/kWh for Multi-Day Energy Storage category

Observations

- The TPC in $s for 2030 is low relative to other technologies. This is largely due to the lower capacity of these systems compared to the other technology types reviewed here (10 MW vs. 50 or 100 MW). This is due in part to the longer-duration design basis chosen for this technology category (100 hours duration vs. 10 hours for most other categories, which increases the denominator on a $/kWh basis). As duration increases, the cost per kWh typically declines for LDES technologies due to the low marginal cost of adding additional hours of storage. However, the cost per kW of power output typically increases with duration, because adding more storage increases overall TPC for a given power output.

Thermal Energy Storage

All the TES technologies have been scaled to have the following performance characteristics:

- **Charge Capacity:** 50 MW
- **Storage Capacity:** 500 MWh_{th}
- **Discharge Capacity:** 25 MW_{th}
- **Discharge Duration:** 20 h

The aggregated capital and O&M cost data for contract years 2025 and 2030 are presented in Table 13 and Table 14, respectively, and a chart comparing 2025 and 2030 TPC ranges in $/$kWh_{th}$ is shown in Figure 12. Note that the technologies that

make up the 2030 group are not the same as those in 2025, i.e., some developers only provided 2025 costs, while others provided both 2025 and 2030 costs.

Table 13. Aggregated 2025 cost data for TES category

Parameter	Reference/Nominal Location		U.S. Lower 48 Location	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
TPC, $	14,665,000	56,902,000	11,898,000	66,178,000
TPC, $/kW$_{th}$	587	2,276	476	2,647
TPC, $/kWh$_{th}$	29	114	24	132
Charge Cost, $/kW	84	535	68	622
Storage Cost, $/kWh$_{th}$	20	38	16	44
Discharge Cost, $/kW$_{th}$	12	455	10	530
Total Annual O&M Cost, % of TPC	0.90	1.07	0.73	1.50

Table 14. Aggregated 2030 cost data for TES category

Parameter	Reference/Nominal Location		U.S. Lower 48 Location	
	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
TPC, $	12,337,000	35,226,000	10,009,000	40,968,000
TPC, $/kW$_{th}$	493	1,409	400	1,639
TPC, $/kWh$_{th}$	25	70	20	82
Charge Cost, $/kW	66	331	53	385
Storage Cost, $/kWh$_{th}$	17	23	14	27
Discharge Cost, $/kW$_{th}$	12	282	10	328
Total Annual O&M Cost, % of TPC	0.90	1.07	0.73	1.51

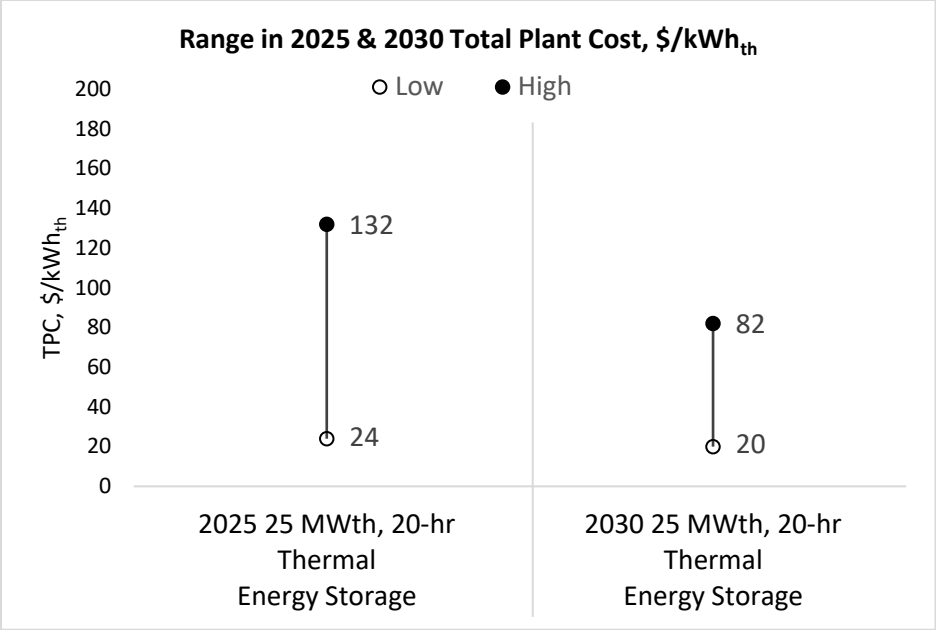


Figure 12. Range in 2025 and 2030 TPC in $/kWh$_{th}$ for Thermal Energy Storage category

Observations

- These systems are largely dependent on being applied and integrated to existing power cycles to which they provide heat. If a new power cycle needs to be built, or if the existing power cycle needs to be upgraded, these costs are not included.
- The range in 2025 TPC is very broad, suggesting disparate technologies with various cost structures went into the aggregated technology category
- The 2030 TPC values are substantially lower than 2025, suggesting that technology developers still consider TES to be early on the cost curve with substantial improvements and cost reductions expected

Based on the submitted cost data, the projected TPC cost reductions from 2025 to 2030 for the Thermal Energy Storage category range from 16 to 47%.

Key Cost Point

Respondents who provided both 2025 and 2030 costs cited both ongoing work (enabling improved performance to increase energy density and longevity) and establishing supply chains/expanding manufacturing capabilities (allowing economies of scale and lower production costs) as key factors in reducing capital costs.

Cost References

Capital costs for lithium-ion battery energy storage systems (BESS) and pumped storage hydropower (PSH) are widely recognized as essential benchmarks for assessing LDES technologies because they represent the most mature and commercially deployed solutions in the storage market. These benchmarks offer a practical reference point for evaluating the economic viability of emerging LDES technologies, which must demonstrate competitive or complementary cost structures to gain market traction. By anchoring comparisons to these proven technologies, stakeholders—including policymakers, investors, and developers—can better understand the cost-performance gap, prioritize R&D investments, and set realistic expectations for commercialization pathways.

EPRI's *Battery Energy Storage Cost Assessment: 2025* [8] provides a cost benchmark for lithium-ion BESS. The report includes estimates of 2025 base year costs of a U.S. electric utility procuring high-tier battery energy systems through a turnkey engineering, procurement, and construction approach for commercial operation in 2026 or 2027. Lithium iron phosphate (LFP) lithium-ion, sodium-ion, nickel-hydrogen, and iron-air BESS technology types were included in 10 MW and 100 MW sizes. LFP BESS were assessed at 4 hours of usable duration, and the estimated overnight capital costs (including owner's costs) for the 10 MW and 100 MW systems were $451/kWh and $385/kWh, respectively. The report did not include cost estimates at longer storage durations for the same power capacity, but EPRI anticipates that power-related costs (inverters, transformers, sitework) would remain unchanged but energy-related costs (battery cells, containers) would scale almost linearly with duration, likely resulting in an approximately 16% lower $ per kWh cost estimate at 10 hours of storage duration. Additional details around the EPRI cost estimate bases include:

- Almost 25% of the costs are from tariffs
- Costs were estimated explicitly using a combination of top-down and bottoms-up methods
- Engineering estimates for footprint density were used in lieu of vendor assumptions based on relative energy density of the cells and enclosure form factor
- Costs include gravel top stone for the majority of surfacing around the site (minimal/no asphalt road paving) and used concrete piers or pads to mount the battery containers, depending on each site's specific geotechnical conditions
- DC block costs include battery modules/racks, battery management system, thermal management system, enclosure, fire detection and suppression, and freight
- Process contingency of 0%, project contingency of 5% of DC block costs plus 10% of EPC costs, and profit of 5% of DC block costs plus 10% of EPC costs

- Costs exclude land, taxes, financing costs, interconnection studies, builder's risk insurance, spare parts, other inventory, and owner's contingency

For PSH, The National Laboratory of the Rockies (NLR) Annual Technology Baseline (ATB) [9] was used to establish a cost benchmark. For an ATB Class 3 PSH plant with a typical generating capacity of 838 MW and a 10-hour storage duration, the conservative estimated 2025 cost is $3,794/kW or $379/kWh. The 2025 cost references for LFP lithium-ion and PSH are summarised in Table 15.

Table 15. 2025 cost references for LFP lithium-ion and PSH

Technology	System Size	Cost Estimate	Source	Cost Metric
LFP Lithium-Ion	10 MW, 4 Hr	$451/kWh	EPRI	Overnight Capital Cost
LFP Lithium-Ion	100 MW, 4 Hr	$385/kWh	EPRI	Overnight Capital Cost
PSH	838 MW, 10 Hr	$379/kWh	NLR	Overnight Capital Cost

5. SUMMARY AND CONCLUSIONS

This study presents the results of a comprehensive cost benchmarking study for LDES technologies, conducted by EPRI in collaboration with the LDES Council. The study attempts to create a more complete and current public cost dataset for selected emerging LDES solutions, which are critical for enabling grid reliability and deep decarbonization.

The LDES Council issued a structured survey to its technology developer members, requesting high-level performance metrics, capital and operating costs, and TRLs for their preferred commercial-scale projects. The survey covered both P2P and P2H applications, with data requested for contract years 2025 and 2030.

EPRI reviewed and normalised the submitted data to a common design basis and location, enabling meaningful comparisons across technologies. Technologies were categorized into five groups:

1. Intraday Electrochemical Energy Storage
2. Intraday Compressed Gas Energy Storage
3. Intraday PHES (P2P configuration)
4. Multi-Day Energy Storage
5. TES

The normalisation process included scaling project sizes and applying location-based cost adjustments using industry-standard references. Capital and O&M costs were aggregated for each technology category, and the results were benchmarked against other industry references. While direct comparisons were limited due to differences in scope and methodology, the study revealed that the LDES Council data generally showed lower expected costs for 2030, particularly for Intraday Electrochemical Energy Storage and TES technologies.

The study also emphasized the importance of consistent TRL assessments and cost certainty classifications. EPRI's independent TRL evaluation ensured uniformity across submissions, and cost estimates were categorized by certainty level using AACE guidelines.

Key Conclusions

- The technology developers active in the industry who provided costs for both contract years expect substantially lower costs in 2030 vs. 2025. Expected cost reductions by 2030 are driven by ongoing work, improved performance, and economies of scale from expanded manufacturing.

- The aggregated and normalised cost data provide actionable insights for utilities and system operators to incorporate LDES technologies into resource planning and capacity expansion models
- The benchmarking methodology enables consistent comparison across diverse technologies and supports planning, modeling, and investment decisions
- Differences between LDES Council data and other references highlight the need for harmonized cost definitions and broader technology coverage to allow fair comparisons

Recommendations

To strengthen the value of this benchmarking effort, the following actions are recommended:

- **Annual Updates:** Updates to the survey and report to reflect evolving technology maturity and market conditions should be done routinely
- **Expanded Participation:** Involvement from technology developers to improve data robustness and granularity is needed
- **Standardized References:** TRL criteria, cost certainty levels, and contingency ranges need standardized references that are publicly available and accepted by stakeholders to ensure consistency in future submissions

This study represents an important step towards establishing a reliable, publicly available resource for LDES cost and performance data. Continued collaboration and refinement will enhance its role in guiding industry stakeholders toward informed decisions in the transition to an abundant energy future.

6. REFERENCES

[1] "Long duration Energy Storage Use Cases," 3002030919, EPRI, Palo Alto, CA, 2024.

[2] G. Salazar and M. Russi-Vigoya, "Technology Readiness Level (TRL) as the Foundation of Human Readiness Level (HRL)".

[3] "Quality Guidelines for Energy Systems Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance," NETL-PUB-22580, 2021.

[4] AACE International Recommended Practice No. 18R-97, "Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for The Process Industries," 2020.

[5] Richardson Engineering, "2023 Richardson International Cost Factors," Richardson Online Cost Database, 2023. [Online]. Available: https://ceskdata.com/products/richardson-online-cost-database/.

[6] Compass International Inc., "2023 Global Construction Costs Yearbook, 23rd Edition".

[7] Arcadis, "New Horizons - International Construction Costs 2023".

[8] "Battery Energy Storage Cost Assessment: 2025," 3002034197, EPRI, Palo Alto, CA, 2025.

[9] "National Laboratory of the Rockies 2024 Annual Technology Baseline," [Online]. Available: https://atb.nrel.gov/electricity/2024/pumped_storage_hydropower. [Accessed December 2025].

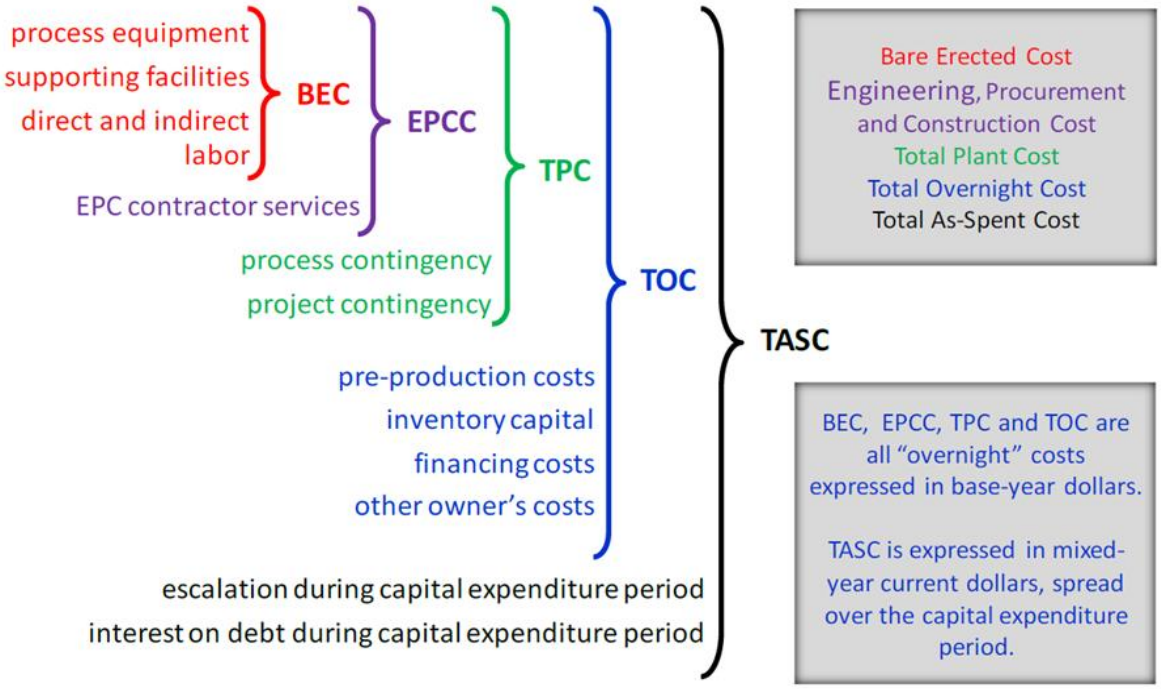
[10] R. James, A. Zoelle and N. Kueln, "Quality Guidelines for Energy System Studies Capital Cost Scaling Methodology: Revision 4 Report," Department of Energy National Energy Technology Laboratory, 2019.

[11] A. Hayashi, K. Noi, A. Sakuda and M. Tatsumisago, "Superionic Glass-Ceramic Electrolytes for Room-Temperature Rechargeable Sodium Batteries," *Nature Communications,* p. 3, 2012.

A. BLANK SURVEY

Instructions, Item Descriptions Worksheet

Item	Item Description
Preferred Commercial Storage Capacity [MWhe]	The maximum storage capacity in terms of discharged electricity.
Preferred Commercial Charging Capacity [MWe]	The maximum rate of electrical input used to charge.
Preferred Commercial Discharging Capacity [MWe]	The maximum rate of electrical power generation.
Storage System Capital Cost [$]	The capital costs attributable to storage system. Note, this is **not** the marginal cost of adding more storage duration.
Charge System Capital Cost [$]	The capital costs attributable to charging system.
Discharge System Capital Cost [$]	The capital costs attributable to discharging system.
Nominal Location	The assumed location of the cost estimate (if applicable).
Balance-of-Plant Costs [$]	The capital costs for balance of plant which are **not** attributable to storage, charge, or discharge capacity.
Site Work [$]	The capital costs for site work which are **not** attributable to storage, charge, or discharge capacity.
Controls [$]	The capital costs for controls which are **not** attributable to storage, charge, or discharge capacity.
Fixed O&M Costs [$/kWe-yr]	The fixed yearly costs for O&M. Include annualized costs of expected equipment replacement and augmentation.
Variable O&M Costs[$/MWhe-discharged]	The incremental costs O&M for each MWhe-discharged.
Expected Lifetime [years]	The expected economic lifetime of the project.
Contingency [%]	The contingencies included in the stated costs, expressed as a percent applied on top of the engineering, procurement, and construction cost.



Source: NETL, Link

Power-to-Power Survey Worksheet

	LDES Council Power-to-Power Cost Survey		
	Instructions: Please fill out all relevant fields below. Ensure that you provide accurate and complete information. If your TRL level is 4 and above, please provide values expected in 2030. For TRL levels 6 and above, please provide values in 2025.		
1	**General Information**		
1.1	Company Name:		
1.2	Contact Person:		
1.3	- Email:		
1.4	- Phone:		
1.5	Technology Type: - Lithium-Ion, Lead Acid, etc.		
1.6	TRL level:		
		2025 cost	**Expected 2030 cost**
2	**Project Information**		
2.1	Nominal Location		
2.2	Project Footprint [square feet or acres]		
3	**Cost Information**		
3.1	Total Capital Costs (USD):	0	0
3.2	Contingency Included [%]		
3.3	Storage System Capital Cost [$]		
3.4	Charge System Capital Cost [$]		
3.5	Discharge System Capital Cost [$]		
3.6	Balance-of-Plant Costs [$]		
3.7	Site Work [$]		
3.8	Controls [$]		
3.9	Fixed O&M Costs [$/kWe-yr]		
3.10	Variable O&M Costs[$/MWhe-discharged]		
4	**Resource Characteristics**		
4.1	Resource Lifetime (Years):		
4.2	Round-Trip Efficiency (Electrical Energy Out / Electrical Energy In) (%):		
4.3	Preferred Commercial Storage Capacity [MWhe]		
4.4	Preferred Commercial Charging Capacity [MWe]		
4.5	Preferred Commercial Discharging Capacity [MWe]		
4.6	Nominal Charge Duration (0 to 100% State of Charge) [h]		
4.7	Nominal Discharge Duration (100 to 0% State of Charge) [h]		
4.8	Storage Capacity Degradation Rate (%/year)		
4.9	Assumed Full-Cycle Equivalents Per Year (0% to 100% to 0% State of Charge)		
4.10	Depth of Discharge (%):		
5	**Additional Information**		
5.1	Certainty Level of Cost Estimates:		

	- High, Medium, Low		
5.2	Additional Notes or Comments:		

Notes

1. Nominal Location should be a favourable project site. If flexible, choose Charlotte, NC as the location.
2. The year for the cost estimate is the date a project would be contracted, e.g., "notice to proceed" or "final investment decision"
3. Project size (4.3 to 4.5) should be the preferred size of a commercial project (charge rate in MW, storage capacity in MWh, and discharge rate in MW). If flexible, select a 10 MW or 100 MW discharge power and 10-hour discharge duration.
4. Contingency costs should be distributed proportionally among the subsystem costs 3.3 through 3.8
5. Items 3.3 through 3.8 should add up to 3.1. Avoid double-counting.
6. Costs should be stated as total project cost which include equipment, materials, labour, engineering fees, and contingencies. Assume non-union labour rates.

Power-to-Heat Survey Worksheet

	LDES Council Power-to-Heat Cost Survey		
	Instructions: Please fill out all relevant fields below. Ensure that you provide accurate and complete information. If your TRL level is 4 and above, please provide values expected in 2030. For TRL levels 6 and above, please provide values in 2025.		
1	**General Information**		
1.1	Company Name:		
1.2	Contact Person:		
1.3	- Email:		
1.4	- Phone:		
1.5	Technology Type: - Lithium-Ion, Lead Acid, etc.		
1.6	TRL level:		
		2025 cost	**Expected 2030 cost**
2	**Project Information**		
2.1	Nominal Location		
2.2	Storage Medium		
2.3	Form of Delivered Heat (Fluid, Pressure, Temperature)		
2.4	Project Footprint [square feet or acres]		
3	**Cost Information**		
3.1	Total Capital Costs (USD):	0	0
3.2	Contingency Included [%]		
3.3	Storage System Capital Cost [$]		
3.4	Charge System Capital Cost [$]		
3.5	Discharge System Capital Cost [$]		
3.6	Balance-of-Plant Costs [$]		
3.7	Site Work [$]		
3.8	Controls [$]		
3.9	Fixed O&M Costs [$/kWth-yr]		
3.10	Variable O&M Costs[$/MWhth-discharged]		
4	**Resource Characteristics**		
4.1	Resource Lifetime (Years):		
4.2	Round-Trip Efficiency (Delivered Heat Out / Electrical Energy In) (%):		
4.3	Preferred Commercial Storage Capacity [MWhth]		
4.4	Preferred Commercial Charging Capacity [MWe]		
4.5	Preferred Commercial Discharging Capacity [MWth]		
4.6	Nominal Charge Duration (0 to 100% State of Charge) [h]		
4.7	Nominal Discharge Duration (100 to 0% State of Charge) [h]		
4.8	Storage Capacity Degradation Rate (%/year)		
4.9	Assumed Full-Cycle Equivalents Per Year (0% to 100% to 0% State of Charge)		
4.10	Depth of Discharge (%):		

5	Additional Information		
5.1	Certainty Level of Cost Estimates: - High, Medium, Low		
5.2	Additional Notes or Comments:		

Notes

1. Nominal Location should be a favourable project site. If flexible, choose Charlotte, NC as the location.
2. The year for the cost estimate is the date a project would be contracted, e.g., "notice to proceed" or "final investment decision"
3. Project size (4.3 to 4.5) should be the preferred size of a commercial project (charge rate in MW, storage capacity in MWh, and discharge rate in MW). If flexible, select a 10 MW or 100 MW discharge power and 10-hour discharge duration.
4. Contingency costs should be distributed proportionally among the subsystem costs 3.3 through 3.8
5. Items 3.3 through 3.8 should add up to 3.1. Avoid double-counting.
6. Costs should be stated as total project cost which include equipment, materials, labour, engineering fees, and contingencies. Assume non-union labour rates.

B. TRL CRITERIA

A TRL taxonomy, originally developed by the National Aeronautics and Space Administration, has been adapted by EPRI to assess the readiness and track the development of energy storage technologies. The main benefit of this taxonomy is to place in perspective the technical readiness that has been achieved for a given technology and anticipate the cost and time required to advance the technology to TRL-9, the first commercial installation. It is also a useful tool for quickly communicating the relative technical maturity of any energy storage technology without the need to explain the details of its current state of development and for comparing the timing and costs of development among similar technologies.

The taxonomy includes Criteria for achieving, estimates of time to achieve, and relative estimates of cost to achieve each of the nine (9) TRLs.

TRL-1 Basic Principles Observed and Reported

- Observation of material properties or other physical/chemical phenomena
- Scientific research begins to be translated into applied research and development (R&D)

Cost to Achieve – The unique costs for the technology under consideration are very low at this level. Investment or cost is borne by broad scientific research programs.

Schedule to Achieve – Weeks or months

TRL-2 Formulation of the Application

- Practical applications of basic physical principles are “invented” or identified
- Generalizations assumed for physical/chemical data not readily available
- Primarily an analytical step rather than a laboratory step
- Batteries – New class of materials synthesized

Cost to Achieve – The unique costs for the technology under consideration are very low at this level. Investment or cost is borne by broad scientific research programs.

Schedule to Achieve – Weeks or months

TRL-3 Proof-of-Concept

- Initiation of active R&D for the specific application
- Detailed analytical studies to design the application and predict its performance
- Laboratory studies that physically verify the engineering/scientific assumptions of the analytical studies
- Batteries – Proven performance in half cells

Cost to Achieve – At this level, noticeable resources in time and limited laboratory studies will be required. The “unique” cost that is technology specific will remain low.

Schedule to Achieve – 6–12 months

TRL-4 Component Validation in a Laboratory Environment

- Component-level assemblies are created from available “pieces” as a functional unit in a laboratory setting
- Test assemblies should be generally consistent with the eventual system but are relatively “low-fidelity”
- Batteries – Proven performance in lab-scale full cells

Cost to Achieve – The “unique” cost that is specific to the technology will be low to moderate. Investment cost will be technology dependent, but probably several factors greater than the cost to achieve TRL-3.

Schedule to Achieve – Likely to require 6–24 months

TRL-5 Component Validation – Pertinent Technology Components are Validated in a Relevant Environment

- Component-level assemblies are designed and function independently as a unit
- Relevant environment is likely to be a laboratory or a small process development unit that simulates the operational environment
- One to several component technologies might be involved in the validation
- Batteries – Material scale-up, cell testing, and scale-up to pack

Cost to Achieve – The “unique” cost that is specific to the technology will be moderate. Investment cost will be technology dependent, but probably several factors greater than the cost to achieve TRL-4.

Schedule to Achieve – Likely to require 12–24 months

TRL-6 Process Development Unit – Consists of Prototype Components in a Relevant Environment

- Prototype components are those whose design and function are essentially the same as expected for full-scale deployment

- Full system integration is not required at this stage
- Relevant environments may include field power plant settings or smaller pilot/test plant installations

Cost to Achieve – These costs are technology and demonstration specific. The costs will be solely dedicated to the technology being developed. They are a fraction of TRL-7 costs.

Schedule to Achieve – Design and construction are likely to require 12–24 months. Operations are likely to require an additional 12–24 months. Total time required is therefore likely to be 24–48 months.

TRL-7 Pilot Plant – Integrated, Fully Functional Prototype that Incorporates All of the Features of the Anticipated Full-Scale Deployment in an Operational Environment

- Scale: Size/capacity no less than about 5% of the capacity required for full-scale implementation
- Include all components or unit processes expected at full scale
- Can be deployed as an adjunct to an operating power plant
- Deploy an operations/control system of a scope comparable to full-scale implementation of the technology

Cost to Achieve – These costs are technology and demonstration specific. The costs will be solely dedicated to the technology being developed (generally no revenue is generated by operations). These costs will be significantly higher (an order of magnitude or more) than TRL-6 costs and may approach TRL-8 costs.

Schedule to Achieve – Design and construction are likely to require 12–24 months. Operations are likely to require an additional 12–36 months. Total time required is therefore likely to be 24–60 months. Design may begin before TRL-6 is accomplished if the results are promising.

TRL-8 Commercial Pilot Plant – Deployment of the Technology in Its Final Form and Under Expected Conditions

- Scale: Size/capacity no less than about 25% of the capacity required for full-scale implementation
- Performance guarantees supportable by TRL-7 experience including capacity, material use/production, and energy use/production
- TRL-8 may be bypassed if achieving TRL-7 provides sufficient confidence to vendors and customers for commercial service requirements of TRL-9

Cost to Achieve – These costs are technology specific but may be the highest cost for the technology deployment due to diseconomies of scale and “first-of-a-kind” costs. Cost/benefit ratio may be close to commercial requirements. Operating benefits are likely to exceed operating costs. Capital cost recovery is however unlikely.

Schedule to Achieve – Design is likely to require 12 months. Construction may require 12–36 months. Demonstration of operational objectives is likely to require at least 1 maintenance cycle of about 24–48 months. Total time required is therefore likely to be 4–7 years. Design may begin before TRL-7 is accomplished if the results are promising.

TRL-9 Commercial Plant – Normal Commercial Service

- Scale: Full-scale implementation
- Enforceable performance guarantees including capacity, material use/production, and energy use/production
- Standard industry warrantees

Cost to Achieve – These costs are technology specific but, on a unit output basis, are generally less than the cost of TRL-8. However, there may be a cost premium for this “first-of-a-kind” installation, particularly if TRL-8 has been bypassed. Future implementation costs are expected to decline as more installations are contracted and completed.

Schedule to Achieve – Design is likely to require 12 months. Construction may require 12–36 months. Demonstration of operational objectives is likely to require at least 1 maintenance cycle of about 24–48 months. Total time required is therefore likely to be 4–8 years. Design is likely to begin before TRL-8 is accomplished. If TRL-8 is bypassed, design may begin before TRL-7 is accomplished if the results are promising.

C. DETAILS ON SCALING COSTS

The methodology for applying the cost scaling is shown in the equation below.

$$SC = RC * (\frac{SP}{RP})^{Exp}$$

Where:

- Exp – Scaling factor
- RC – Reference Cost
- RP – Reference Parameter
- SC – Scaled Cost
- SP – Scaling Parameter

The equation captures the non-linear relationship that increasing size has with cost, where typically cost will increase at a slower rate than size. If the scaling exponent is 0, then the cost remains fixed with changing size. If the scaling exponent is 1, then cost is linearly proportional to size. One of the key considerations in scaling capital costs for different plant sizes is the number of trains to be used. If equipment is made larger but in a single train, there are better economies of scale, and the exponent may be in the 0.6 to 0.7 range. If multiple parallel trains are needed to scale up, then there is less economy of scale, and the exponent may be more like 0.9 to 0.95.

Cost scaling exponents were determined for each technology by investigating representative cost scaling factors from EPRI's in-house cost estimates and developing weighted-average cost scaling factors for the primary subsystems: charge capacity, storage capacity, and discharge capacity [10].

Capital costs provided in the surveys, whether a single TPC value or TPC broken down into the six subsystem costs, were reallocated into the three primary subsystem costs and then scaled using the cost scaling factors for each subsystem. The average scaling factors used for the technology categories are shown in Table 16.

Table 16. Average scaling factors for technology categories

Technology Category	Average Scaling Factors		
	Charge	Storage	Discharge
Intraday Electrochemical Energy Storage	0.943	0.977	0.943
Thermal Energy Storage	0.792	0.889	0.662
Intraday Compressed Gas Energy Storage	0.844	0.851	0.825
Multi-Day Energy Storage	0.943	0.977	0.943
Intraday Pumped Heat Energy Storage	0.800	0.824	0.800

O&M costs were also scaled but used a slightly different methodology than the one used for capital costs. Fixed O&M cost was set to scale with TPC using a scaling factor of 0.5. This low scaling exponent means that fixed O&M expenses like plant staff do not scale linearly with plant size. However, for this analysis, it was assumed that variable O&M costs do not scale and hence were unchanged.

The LDES Council unites global industry leaders, customers and policymakers to accelerate the innovation, commercialisation, and deployment of long duration energy storage technologies. By advancing real projects already in motion and sharing data-driven insights, we help scale LDES solutions today – educating utilities and industrial customers on how long duration energy storage supports their goals, informing policymakers to enable adoption and advocating for flexible and secure energy systems that meet the growing demands of electrification, serving communities and industries worldwide.

ldescouncil.com

Founded in 1972, EPRI is the world's preeminent independent, non-profit energy research and development organization, with offices around the world. EPRI's trusted experts collaborate with more than 450 companies in 45 countries, driving innovation to ensure the public has clean, safe, reliable, and affordable access to electricity across the globe. Together...shaping the future of energy.®

epri.com