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(ES TCP)

Task 41

Evaluating the Economics of Energy Storage Systems – EcoEneSto



Final Report

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LIST OF ABBREVIATIONS

ANF	Annuity Factor
BTES	Borehole TES
CAES	Compressed Air Energy Storage
CapEx	Capital Expenditure
CHC	Charging Costs
CHP	Combined Heat and Power
DH	District Heating
ES	Energy Storage
ESG	Environmental, Social, Governance
ESS	Energy Storage System
GHG	Greenhouse Gas
INC	Investment Costs
IRR	Internal Rate of Return
KPI	Key Performance Indicator
LCC	Life Cycle Costs
LCOE	Levelised Cost of Energy
LCOS	Levelised Cost of Storage
LHTES	Latent Heat TES
N_{cycle}	Number of Storage Cycles per Year
NPV	Net Present Value
O&M	Operation & Maintenance
OMC	Operation & Maintenance Costs
OpEx	Operational Expenditure
PHS	Pumped Hydro Storage
PTES	Pit TES
REC	Reference Energy Costs
REV	Revenue
ROA	Real option analysis
ROI	Return on Investment
RTE	Round Trip Efficiency
SC	Storage Capacity

SCC	Storage Capacity Costs
STES	Sensible TES
TES	Thermal Energy Storage

KEY MESSAGES AND POLICY RECOMMENDATIONS

KEY MESSAGES

- **Energy storage economics are inherently application-specific:** meaningful economic evaluation is only possible when storage technologies are assessed within clearly defined applications, including required power, energy capacity, duration, cycling frequency, and system context.
- **There is no universally “cheapest” or “best” storage technology:** cross-technology cost comparisons without reference to application lead to misleading conclusions and should be avoided in scientific and policy analysis.
- **The economic value of energy storage lies in the services provided, not in stored energy itself:** revenues are primarily generated through discharge-related services (e.g. grid balancing, peak supply, flexibility), while stored energy is rarely remunerated.
- **Cycle frequency is a key driver of profitability:** short-term, high-cycling applications favour more expensive but high-performance technologies, whereas long-duration or seasonal storage requires very low specific storage capacity costs.
- **Revenue stacking is often essential for viable business cases:** single-use applications are frequently insufficient to recover investment costs under current market conditions.
- **Standardised KPIs enable transparency and comparability:** harmonised technical, economic, environmental, and social KPIs are necessary for robust evaluation and informed decision-making.
- **Regulatory and market frameworks critically shape economic outcomes:** many technically beneficial storage applications remain uneconomic due to missing or inadequate remuneration mechanisms caused by regulations.

POLICY RECOMMENDATIONS

- **Mandate application-based evaluation of energy storage:** Require that policy assessments, funding schemes, and regulatory impact analyses evaluate energy storage systems in specific use cases rather than at technology level.
- **Enable and reward flexibility services across all energy sectors:** Design markets and tariffs that explicitly remunerate flexibility, balancing, reserve provision, and congestion relief in electricity, heating/cooling, and hydrogen systems.
- **Facilitate revenue stacking:** Remove regulatory barriers that prevent energy storage from providing multiple services simultaneously or across markets, and harmonise market participation rules.
- **Recognise long-duration and seasonal storage as system infrastructure:** Develop dedicated support mechanisms for long-term storage where societal value (e.g. security of supply, decarbonisation) exceeds short-term market revenues.

- **Adopt harmonised KPI frameworks in policy and planning:** Integrate standardised economic, environmental, and social KPIs into permitting, funding, and strategic energy system planning processes.
- **Align regulation with learning and innovation dynamics:** Support early deployment of emerging storage technologies to accelerate learning effects while avoiding lock-in to suboptimal solutions.
- **Ensure technology-neutral but application-sensitive policy design:** Avoid prescriptive technology mandates; instead, define performance- and service-based criteria that allow different storage solutions to compete fairly.
- **Strengthen data transparency and case study dissemination:** Support open databases and standardised reporting of techno-economic performance from real-world storage projects to improve model accuracy and comparability.
- **Integrate energy storage into long-term energy transition strategies:** Explicitly account for the role of storage in achieving high renewable shares, sector coupling, and system resilience in national and international energy strategies.

MAIN RESULTS IN A NUTSHELL

Task 41 provides a comprehensive, application-oriented assessment of the economics of energy storage systems across technologies, sectors, and use cases. The main outcome of Task 41 is that the economic viability of energy storage cannot be assessed at the technology level alone, but only within specific applications, where technical requirements, revenue mechanisms, and system context jointly determine value creation.

NO “BEST” STORAGE TECHNOLOGY—ECONOMICS ARE APPLICATION-SPECIFIC

A key finding is that cross-technology cost comparisons are not meaningful without a clearly defined application. Energy storage technologies differ fundamentally in cost structure, power-to-energy ratios, lifetimes, efficiencies, and scalability. Economic evaluation therefore requires matching storage properties (capacity, power, duration, and cycling frequency) to the needs of a concrete use case (e.g. seasonal heat storage, grid balancing, and short-term arbitrage). Only at this level can costs and revenues be consistently compared.

VALUE CREATION DEPENDS ON SERVICES, NOT STORED ENERGY

Energy storage derives its economic value primarily from the services it provides, not from the stored energy itself. Revenues are typically linked to:

- Energy discharge (e.g. peak supply, arbitrage),
- Power-related services (e.g. frequency regulation, reserve provision),
- Avoided system costs (e.g. grid reinforcement, curtailment),
- Resilience and security-of-supply benefits in specific niches.

Stored energy as such is rarely remunerated, except in emergency or backup applications. Consequently, cycle number and utilization rate are decisive for profitability, favouring short-term, high-cycling applications unless very low-cost storage is available.

HARMONISED KPIS ENABLE MULTI-DIMENSIONAL ASSESSMENT

Task 41 establishes a structured KPI framework covering technical, economic, environmental, and social dimensions. Traditional metrics such as LCC, LCOS, NPV, IRR, and payback time are complemented by indicators for environmental impacts (e.g. life-cycle GHG emissions, resource depletion) and social aspects (e.g. acceptance, land use, resilience benefits). This enables a more holistic assessment aligned with energy transition objectives and ESG considerations.

THREE COMPLEMENTARY ECONOMIC EVALUATION APPROACHES

To operationalise application-specific assessment, the Task develops and applies three methodological approaches:

- **Benefit–Revenue–Cost approach:** Explicitly links technical services to monetisable benefits and identifies non-remunerated benefits due to present regulation gaps.
- **Maximum Acceptable Energy Storage Cost:** Determines cost thresholds under which storage becomes competitive for a given application.
- **12-step valuation and business model framework:** Integrates system definition, stakeholder analysis, and economic evaluation into a structured decision-support process.

Case studies across thermal, electrical, and chemical storage confirm that viable business cases often rely on revenue stacking and favourable regulatory conditions.

The examples presented primarily refer to technologies at higher Technology Readiness Levels (TRLs). Nevertheless, the underlying economic assessment methodologies are also applicable at earlier stages of technology development, provided that the greater uncertainty in technical and economic input parameters is appropriately taken into account.

POLICY AND MARKET DESIGN ARE DECISIVE

Finally, the Task highlights that regulatory frameworks strongly influence storage economics, often determining whether technical benefits can be translated into revenues. Clear market access, remuneration for flexibility and system services, and recognition of long-duration storage remain critical enablers for large-scale deployment.

EXECUTIVE SUMMARY

1 Short Description of Task 41

1.1 Objectives and Scope

The main goal of the Task was to evaluate the economic efficiency of energy storage systems on a theoretical basis using scientific methods. Within the Task, a coordinated evaluation of energy storage in all applications relevant to the energy system (centralised/decentralised storage; all sectors: electricity, heating/cooling, and mobility) was carried out. All storage technologies (electrical, thermal, and chemical) were considered.

The Task aimed to contribute to a better understanding of how a certain value is created from a certain benefit of an energy storage technology or system and how this can be translated into a business case in a systematic way.

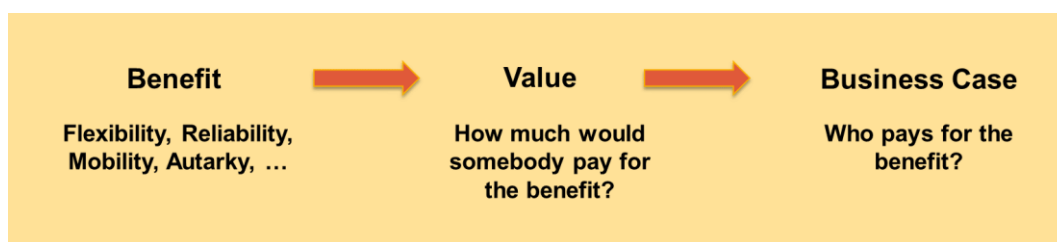


Figure 1-1: Benefits, value, and business case of energy storage systems.

The key objectives of the Task were:

- Collection of methods to evaluate the economic viability of energy storage systems for specific applications (e.g. the maximum acceptable storage costs approach)
- Definition of key performance indicators (KPIs) to evaluate the economics of energy storage
- Inventory of economically interesting energy storage configurations and deriving preferable conditions for energy storage operation in actual applications (technical and non-technical)
- Identification of difficult cases in which existing benefits of energy storage solutions cannot be transferred into possible business cases
- Comparison of energy storage configurations to solutions with other flexibility measures and to systems without energy storage
- Analysis of the influence of regulatory framework conditions on possible energy storage business cases by listing specific examples
- Establish a framework for the development of business cases for energy storage

The Task covered the following:

- All energy storage technologies: electrical, thermal, chemical
- All relevant energy storage applications in the energy system
 - Centralised, decentralised
 - All sectors: electricity, heating/cooling and mobility

Through an international approach, a wide variety of approaches for different energy systems were integrated. In parallel, to identify possible business cases, economically promising storage configurations were collected by the experts. An interdisciplinary approach (technical and economic background) was achieved by integrating relevant expertise from the participating countries.

1.2 Organisational Structure

The work of the Task was split into 4 Subtasks.

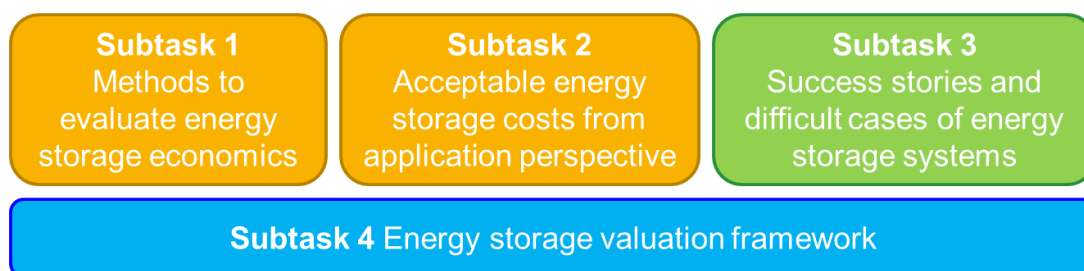


Figure 1-2: EcoEneSto Subtask structure.

Subtask 1 focused on calculation methods to evaluate energy storage economics. In Subtask 2, one specific method to evaluate energy storage economics was further developed. Economically successful energy storage implementations and difficult cases without a viable business model were collected in Subtask 3. Bringing the results from Subtasks 1 to 3 together, Subtask 4 was to establish an energy storage valuation framework.

The Subtask Managers were:

- Subtask 1: Justin Chiu, KTH, Sweden
- Subtask 2: Christoph Rathgeber, ZAE, Germany
- Subtask 3: Jianhua Fan, DTU, Denmark
- Subtask 4: Joris Koornneef, TNO, The Netherlands

For the structure of the final report, the authors have decided not to present the results of Task 41 in order of the four Subtasks. Instead, they first provide an introduction to the topic of energy storage and the costs of energy storage systems, followed by a chapter on the economic, technical, and social KPIs of energy storage systems. The three methods developed in Task 41 for evaluating the economic efficiency of energy storage systems are then presented in separate chapters.

1.3 Duration of Task

Task 41 had a duration of three years. It started on 1 July 2022 and ended on 30 June 2025.

1.4 Experts Meetings

Table 1-1 gives an overview of the expert meetings in this Task.

Table 1-1: Details about the date and location of each expert meeting.

City	Country	Date	# of Participants
Berlin	Germany	14-16 September 2022	30
Linz	Austria	10-12 May 2023	27
Utrecht	Netherlands	27-29 September 2023	47*
Copenhagen	Denmark	20-22 March 2024	32 + (40)*
Stockholm	Sweden	2-4 October 2024	52*
Lucerne	Switzerland	7-9 May 2025	33

*As part of the experts meetings in Utrecht, Copenhagen and Stockholm an industry workshop was held with national companies and institutions on the first day of the meeting with a broader group of participants.

1.5 Participation

14 countries have declared their interest in participating in the Task at the 90th ExCo meeting (online) in November 2020. During the experts meetings overall 109 people from 16 countries and 63 different organizations from both research facilities and companies participated in Task 41. Industry workshops as part of the experts meeting attracted more participation from the energy storage industry.

Table 1-2: List of participating institutions per country.

Country	Institution
Austria	AEE INTEC, Energieinstitut Linz, FIB, FH Wels
Canada	CanmetENERGY
China	Tsinghua University
Denmark	DTU, PlanEnergi, Aalborg CSP, Copenhagen Infrastructure Partners CIP, Hyme, Energienet, EWII, Heliac
France	INSA Lyon
Germany	BP Europa SE, BVES, Christ&Company Consulting GmbH, DIAS, DLR, Malta Hochtemperatur Wärmepumpen Stromspeicher GmbH, EDF Renewables Storage Deutschland GmbH, Fraunhofer Institute for Solar Energy Systems ISE, MAN Energy Solutions, Projektträger Jülich, Rubitherm Technologies GmbH, ZAE Bayern, KIT, Kraftblock GmbH, Otto-von-Guericke-Universität
Italy	Ricerca sul Sistema Energetico - RSE S.p.A.
Japan	University of Tokyo

Country	Institution
Norway	Cartesian, SINTEF Energy Research
The Netherlands	CE Delft, Corre Energy, Dr Ten, EBN, Eneco, Ennatuurlijk Aardwamte, GIGA Storage, Greenport West-Holland, Newton Energy Solutions, Recoy, RVO, TNO, Trecodome, Utrecht University
Sweden	Alfa Laval, KTH Royal Institute of Technology, Flower SE, Polestar, Southernlights, Vattenfall, Wind Energy Expert
Switzerland	HSLU
United Kingdom	Business Lift, Imperial College London, University of Birmingham, SSE Thermal, Swansea University
United States of America	Fluence Energy

2 Summary of the Final Report

2.1 Economic Properties of Energy Storage Technologies

The first chapter of the final report provides the conceptual foundation for evaluating energy storage economics by linking technology properties, service provision, and application-specific value creation. While the chapter begins with a general classification of storage technologies (electrical, thermal, chemical) and their cost characteristics, its core contribution lies in formalizing how economic value arises from storage and why meaningful evaluation is only possible within clearly defined applications.

It is a central principle: The economic value of energy storage is derived from the services it provides, not from the act of storing energy itself. In energy systems with high shares of variable renewables, storage primarily delivers value by enabling temporal decoupling of supply and demand, thereby supporting system balance across electricity, heat, and fuel vectors.

Energy storage systems are characterised by two fundamental technical parameters—energy capacity (how much energy can be stored) and power capacity (how fast energy can be charged or discharged). The relative importance of these parameters is application-dependent. Long-duration applications such as seasonal heat storage are dominated by energy capacity requirements, whereas short-duration applications such as grid stabilization or fast charging infrastructure are power-dominated. This distinction has direct economic implications, as energy-related and power-related cost components scale differently across technologies.

The chapter further distinguishes between benefits, value, and business cases. Benefits describe the technical or system-level contribution of storage (e.g. flexibility, reliability, autonomy). Value emerges only when these benefits are associated with a willingness to pay by identifiable actors. A viable

business case exists only if this value can be monetised through market mechanisms or contractual arrangements.

Importantly, the three operational stages of storage—charging, storing, and discharging—do not contribute equally to revenue generation. In most applications, revenues are generated during discharging, when energy or power services are delivered. In some cases, charging can also be remunerated (e.g. absorbing excess renewable generation or providing negative balancing power), but such revenues are typically uncertain and insufficiently predictable to support investment decisions. The stored energy itself is generally not paid for, except in “back-up” applications such as emergency supply or uninterruptible power systems.

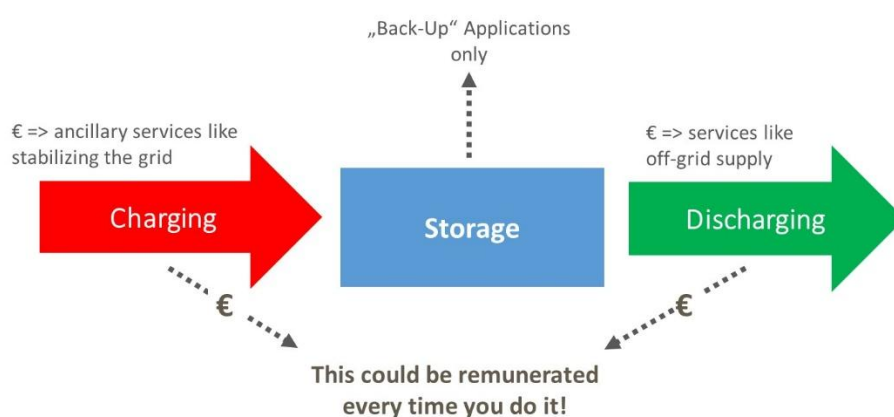


Figure 2-1: Metrics of return on invest in the case of energy storage systems.

A key quantitative driver identified in this section is the number of charge–discharge cycles over time. Because revenues are usually earned per cycle, high-utilization, short-term storage applications can tolerate higher specific investment costs, whereas long-term or seasonal storage with low cycling frequency requires extremely low storage capacity costs to achieve acceptable returns.

It is a decisive methodological conclusion: Economic evaluation of energy storage is only meaningful in the context of a specific application. Generic statements about the cost-effectiveness or competitiveness of storage technologies are inherently misleading because storage technologies differ fundamentally in their cost structures, performance characteristics, and operational constraints.

For any valid economic assessment, both sides of the equation must be specified: On the cost side, the characteristics of the storage technology (investment cost, efficiency, lifetime, degradation, operational costs). On the revenue side, the application-defined requirements, including required energy capacity, power, duration, cycle frequency, and the remuneration mechanisms for delivered services.

Only when these parameters are jointly defined can costs and revenues be consistently compared. This leads to the rejection of technology-level rankings and supports an application-driven matching of storage technologies to system needs.

2.2 Key Performance Indicators for Energy Storage Economics

Recognizing the diversity of storage technologies and applications, the need for consistent methodologies and indicators that enable transparent comparison while respecting application-specific requirements was addressed.

A central outcome is the systematic identification and structuring of key performance indicators (KPIs) across four dimensions: technical, economic, environmental, and social. Technical KPIs (e.g. energy and power capacity, efficiency, lifetime, response time) were defined as essential input parameters for any economic evaluation. Economic KPIs such as life-cycle cost (LCC), levelised cost of storage (LCOS), net present value (NPV), internal rate of return (IRR), payback time, and return on investment (ROI) were reviewed and contextualised with respect to different storage applications and stakeholder perspectives.

As an example, the economic KPIs are summarised in the following Table 2-1.

Table 2-1: Common economic KPIs of energy storage systems.

Economic KPI	Unit	Description
Investment cost / Capital expenditure (CapEx)	€	The upfront amount invested to design, build and commission the facility
Life cycle cost (LCC)	€	Total cost over the system's full lifetime
Levelised cost of storage	€/kWh	Lifetime cost per unit of energy discharged
Installed power capacity cost	€/kW	Cost per unit of discharge power
Installed storage capacity cost	€/kWh	Cost per unit of installed energy storage capacity
CapEx per storage volume	€/m ³ & €/m ²	The investment cost per unit space or area, for thermal energy storage and other space-sensitive technology
Revenue	€	Total income and/or cost savings brought by the energy storage
Payback (PB) time	Years	Time needed to recover the investment via revenue or cost savings
Net present value (NPV)	€	The value of the energy storage cash flow is the sum of the present value of all the future cash flows that the storage will generate
Internal rate of return (IRR)	%	A discount rate where NPV equals to zero
Return on investment (ROI)	%	Ratio of net gain to total cost
Operational & maintenance (O&M) costs / Operational expenditure (OpEx)	€/year or €/cycle	Recurrent costs to keep the system functional, including inspections, repairs, and replacement

Beyond traditional financial metrics, the importance of environmental and social KPIs, including life-cycle greenhouse gas emissions, resource depletion, safety, public acceptance, and contribution to system resilience was emphasised. This broader KPI framework reflects the growing relevance of ESG criteria and system-level impacts in energy system decision-making.

Established economic evaluation methods, including discounted cash flow analysis, LCOS methodologies, and real options analysis (ROA), were also reviewed and compared. Particular attention was paid to the limitations of static methods under conditions of uncertainty, highlighting ROA as a valuable complement for capturing the economic value of flexibility, staged investments, and adaptive decision-making.

Overall, this chapter provides the conceptual and methodological foundation of Task 41. It demonstrates that robust economic assessment of energy storage requires a multidimensional KPI framework and application-specific modelling, forming the basis for the more applied approaches developed in the subsequent chapters.

Social KPIs were not a primary focus of Task 41, which concentrated mainly on the technical and economic performance of energy storage systems. This focus reflects the objective of the Task to assess storage technologies using quantifiable parameters directly related to system performance, costs, and economic viability. Social KPIs are generally more context-dependent and require different assessment approaches. Nevertheless, they can complement technical and economic KPIs when evaluating energy storage systems from a broader sustainability perspective.

2.3 Benefit-Revenue-Cost Approach

The Benefit-Revenue-Cost approach is introduced as a structured method to assess whether the system-level benefits of an energy storage system can be translated into realised revenues and compared against system costs. The approach explicitly distinguishes between benefits (theoretical system value), revenues (monetisable income streams), and costs (investment and operation), thereby addressing a common gap in storage valuation studies.

The method proceeds in three steps. First, all potential benefits provided by the storage system are identified and revenues quantified where possible. These include avoided generation costs, avoided grid reinforcement, flexibility provision, reliability improvements, and resilience benefits. Second, the subset of benefits that can actually be captured as revenues under existing market and regulatory conditions is determined. Importantly, revenues may accrue to different actors than the storage owner, highlighting misalignments between system value and private profitability. Third, these revenues are compared against the full cost structure of the storage system to assess economic viability.

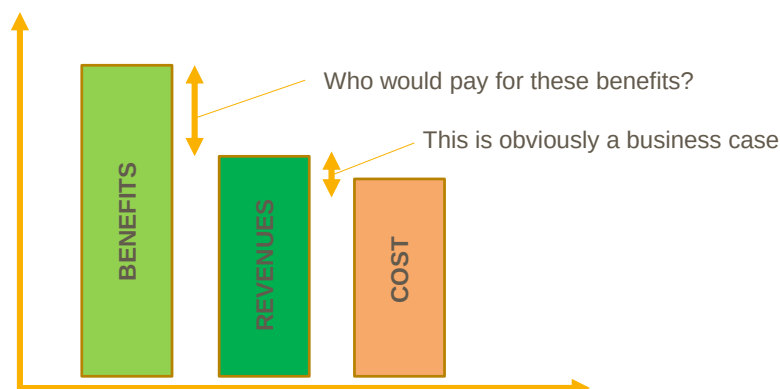


Figure 2-2: Benefit-Revenue-Cost approach developed in Task 41 – illustration for a promising business case.

A key insight of the Benefit-Revenue-Cost approach is that a storage system can be beneficial but not profitable, or profitable for one actor while delivering uncompensated benefits to others. The explicit comparison between benefits and revenues reveals where market failures or regulatory barriers prevent value capture. This makes the approach particularly useful for identifying policy gaps and designing remuneration mechanisms for flexibility services.

The chapter illustrates the methodology using realistic application examples, including power-to-cold storage in refrigeration and mobile thermochemical storage. These examples demonstrate how revenue stacking can improve viability, but also show that single-service business models are often insufficient.

From a technical perspective, the Benefit-Revenue-Cost approach is best suited for system-oriented analysis, early-stage feasibility assessment, and policy evaluation. It does not optimise technology design but instead clarifies who benefits, who pays, and where value leakage occurs. As such, it complements cost-threshold methods (cf. section 2.4) and detailed project valuation frameworks (cf. section 2.5).

2.4 Maximum Acceptable Energy Storage Cost Approach

The Maximum Acceptable Energy Storage Cost approach is a practical method for assessing the economic feasibility of energy storage in specific applications. Rather than asking whether a given storage technology is profitable at its current cost, the approach determines the maximum cost level at which a storage solution becomes economically viable under defined technical, operational, and market conditions.

The approach combines a top-down and a bottom-up perspective. The top-down view derives acceptable storage costs from system-level benefits and avoided costs (e.g. fuel savings, avoided grid investments, flexibility value), while the bottom-up view considers techno-economic characteristics of the storage system, including investment and operating costs.

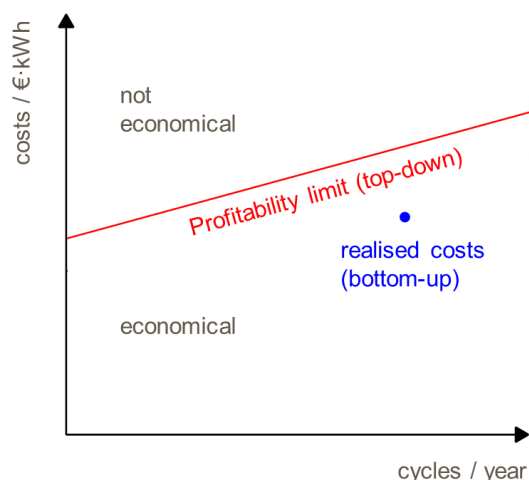


Figure 2-3: Top-down and bottom-up analysis of maximum acceptable energy storage costs.

A key outcome was the extension of the original methodology into three complementary variants: a reference-oriented version, an extended reference-oriented version, and a revenue-oriented version. These variants allow the method to be adapted to different data availability levels, application types, and stakeholder questions. To support practical implementation, an Excel-based tool was developed, enabling transparent and reproducible calculations.

The approach was applied to a broad set of real-world energy storage cases covering thermal, electrical, and chemical storage, as well as short-term and long-term applications. The evaluation revealed that economically successful projects are typically characterised by one or more of the following factors: high utilization rates, access to multiple revenue streams, integration into existing infrastructure (e.g. district heating networks), or operation under favourable regulatory frameworks. In contrast, cases without viable business models often suffer from low cycling frequencies, missing remuneration for system services, or regulatory barriers preventing revenue stacking.

An important finding is that technical feasibility does not imply economic viability. Several storage solutions provide clear system benefits—such as integration of renewable energies or grid stability—but cannot currently translate these benefits into sufficient revenues. This gap highlights the importance of appropriate market design and policy intervention.

2.5 12-Step Approach for Business Model Development

The 12-Step approach is proposed as a comprehensive energy storage valuation and business model development framework. It guides stakeholders from system definition to economic evaluation and business model formulation.

VALUE CREATION & BUSINESS MODEL FRAMEWORK

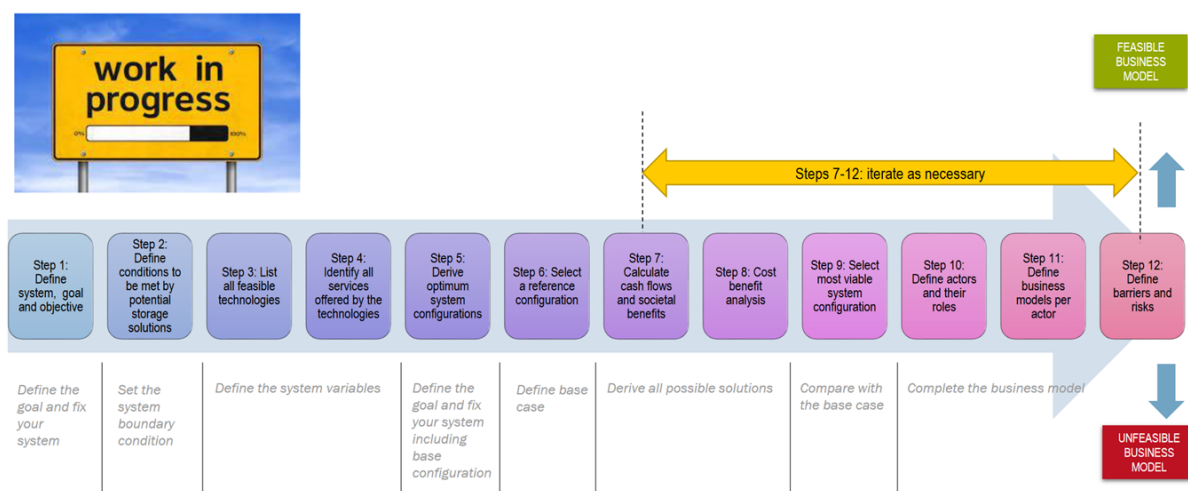


Figure 2-4: Value Creation and Business model framework.

The framework is divided into two main phases. Steps 1–6 focus on system definition and technical design, including application context, required storage services, technology selection, and operational characteristics. Steps 7–12 address economic evaluation, stakeholder analysis, revenue mechanisms, and business model development, integrating financial metrics with regulatory and market considerations.

A key contribution of this approach to the overall Task results is the explicit linkage between technical services, economic value, and paying actors. By systematically identifying who benefits from specific storage services and how these benefits can be monetised, the framework helps bridge the gap between system-level value and project-level business cases.

The framework is technology-neutral and applicable across energy sectors, including electricity, heating and cooling, hydrogen, and industrial applications. It explicitly incorporates uncertainty, regulatory constraints, and the potential for revenue stacking, reflecting the complexity of real-world deployment conditions.

The 12-Step approach demonstrates that successful energy storage deployment requires more than favourable technology costs. Viable business models emerge only when technical design, economic evaluation, and institutional context are aligned. The framework therefore serves as a practical guide for policymakers, system planners, and project developers aiming to translate the benefits of energy storage into bankable projects.

3 Comprehensive Results and Recommendations for Deployment

To assess the economic efficiency of energy storage systems, three methods were developed (further) in Task 41, which differ in their perspective and complexity.

The first method (A) compares the potential benefits and achievable revenues of an energy storage system with its costs (cf. Figure 2-2). The benefits are calculated as the monetary value of all services that could theoretically be offered with this storage system. The revenues correspond to the total realised income from the operation of the storage system. It is possible that the revenues accrue to different actors. By comparing benefits, revenues and costs, it is possible to conclude to what extent a particular energy storage system can be operated economically for certain players or could theoretically be operated economically. The comparison between benefits and revenues shows whether and which benefits could be monetised in addition to the revenues already realised.

The second calculation method (B) considers the maximum acceptable energy storage costs for different applications and users (cf. Figure 2-3). The economic assessment is based on the assumption that the cost of energy from storage must not exceed the cost of alternative energy supply. Using the annuity method, this results in the requirement that the annual costs for the storage investment must not exceed the annual savings in reference energy costs (*top-down* approach). The parameters of the tool are the interest rate on the investment, the target payback period, the reference energy costs and the annual number of cycles; these are compared with the investment costs of the storage facility and the storage capacity, from which the realised storage capacity costs can be calculated (*bottom-up* approach). The methodology was developed in collaboration with companies. Three different approaches are available. Two of the approaches are particularly suitable when the main purpose of the energy storage system is to supply a certain amount of energy and thus reduce the use of alternative energy sources. The third approach is particularly advantageous when considering different sources of income, i.e. when the implementation of a storage system in an application brings several advantages and resulting revenues. An Excel tool has been developed to apply the three approaches and published on the ES TCP website.

The third method (C) comprises twelve steps and evaluates the economic efficiency of energy storage systems holistically and in detail (cf. Figure 2-4). Based on the analysis of the specific application conditions, a techno-economic comparison of potentially usable energy storage technologies is carried out. The relevant players are then defined and their respective business models calculated. If the choice of technologies and players does not result in an economically viable concept, the corresponding steps are repeated and concept variants are examined.

The extended final report starts with an introduction on the economic properties of energy storage technologies (section 4). Economical, technical, and social key performance indicators for energy storage are explained in section 5. Following this, the three evaluation methods (A), (B), and (C) are detailed in sections 7, 6, and 8, respectively.

FINAL REPORT

4 Economic Properties of Energy Storage Technologies

4.1 Energy Storage Technologies - How to Store Energy?

The definition of energy storage in the Strategic Plan of the Energy Storage TCP [1] is as follows:

“An energy storage system can take up energy and deliver it at another point in time. The storage process itself consist of three stages: charging, storage and discharging. After the discharging step, a storage system can be charged again.”

Energy can be stored in different ways. It can be stored as electricity (for example electro-chemically in batteries), as heat or cold in thermal energy storage systems or in molecules. The latter way of storage is also called chemical energy storage and it is quite similar to energy bound in fossil fuels. The only difference is that the chemical energy storage can be “charged” e.g. by electricity via electrolysis producing hydrogen.

Figure 4-1 shows the structure of energy storage technologies following the three main categories just introduced.

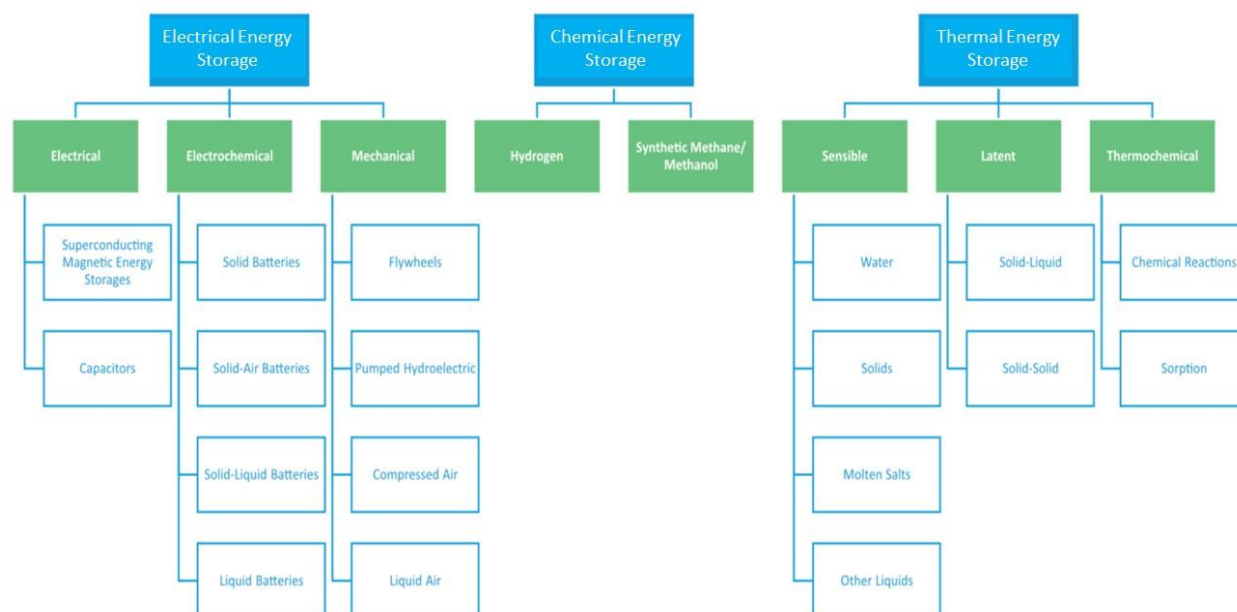


Figure 4-1: Overview of energy storage technologies divided into three main categories (electrical energy storage, chemical energy storage, thermal energy storage).

All these energy storage technologies provide a huge variety of technical and economic properties.

4.2 Energy Storage Technology Cost

Energy storage technologies are a field of intense R&D activities. Many technologies are still under development and show remarkable cost reduction potentials. Figure 4-2 shows the cost development over the installed storage capacity for different electro-chemical energy storage technologies.

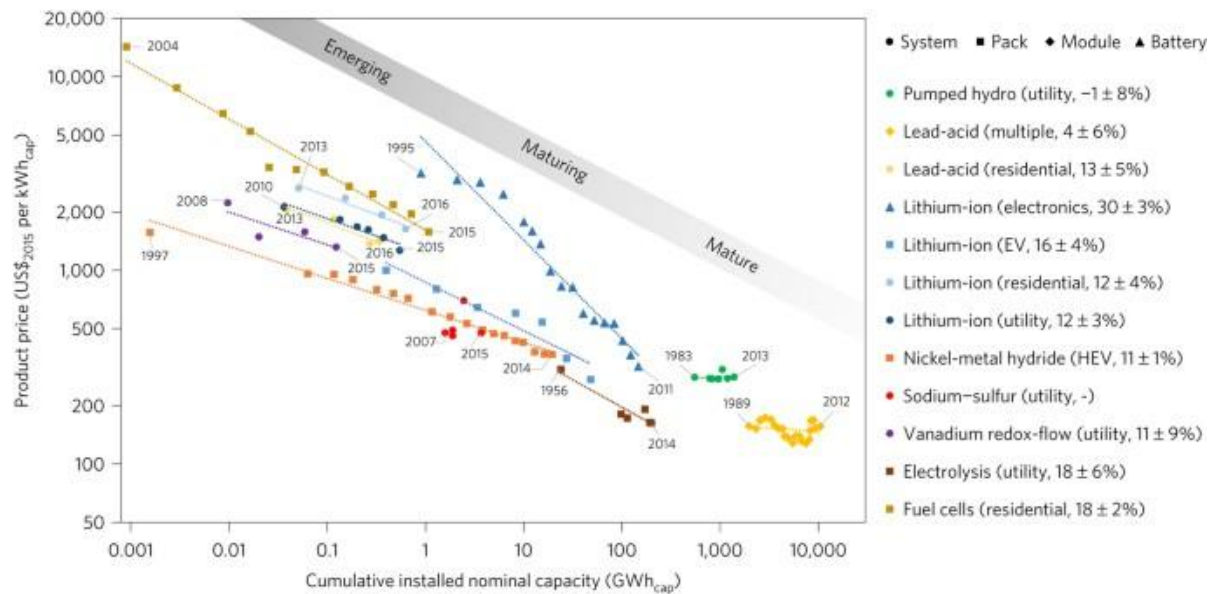


Figure 4-2: Cost development of electro-chemical storage over the installed capacity [2]. (Low image quality as in the source.)

Potential cost reductions are only possible for technologies under development. This means, there might be differences between modules, stacks, and complete battery systems. Components like power electronics might not have the same cost reduction potential as complete battery stacks.

Figure 4-3 shows the learning curve for large hot water energy storages connected to district heating grids. The investment cost is plotted over the water volume, which is equivalent to the potential storage capacity of each installed system. The large systems in the range of 100,000 m³ of hot water volume are in the range of hundreds of GWh storage capacity. These systems represent by far the lowest specific cost per installed storage capacity.

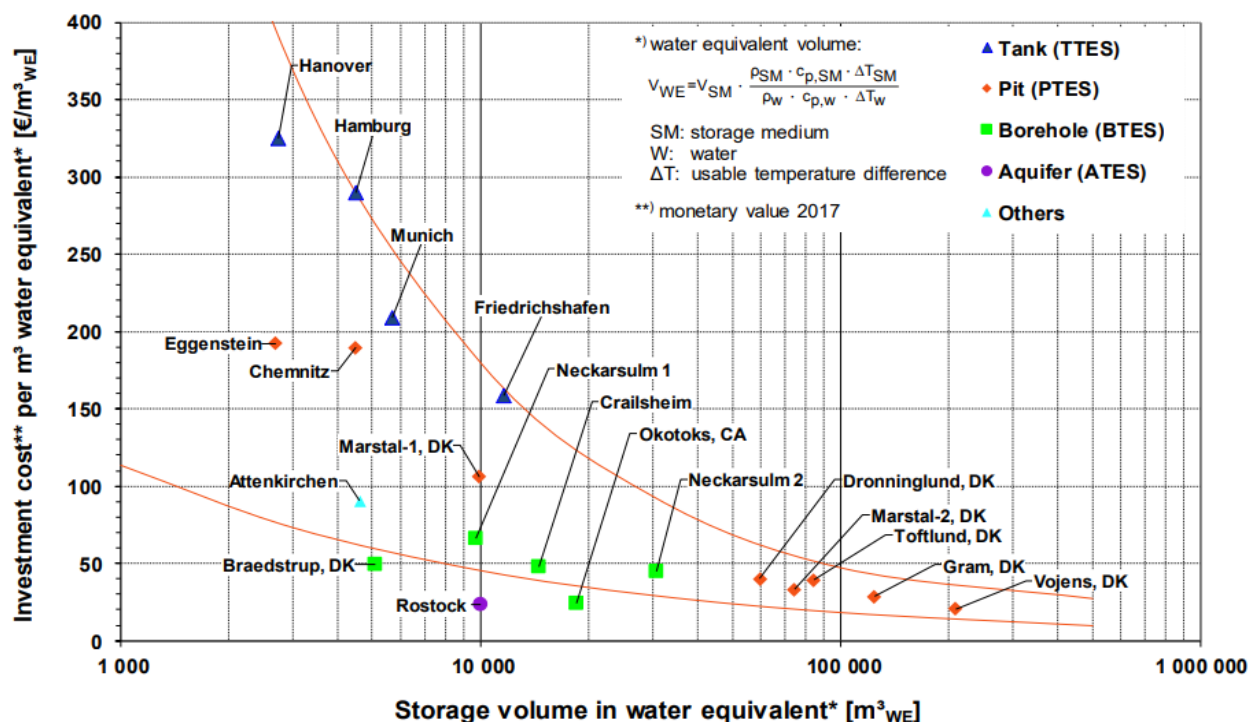


Figure 4-3: Investment cost of large hot water storages over the storage volume [3].

A similar development can be observed for electrolyzers converting electricity into hydrogen. Over the last years the cost per kW could be reduced substantially.

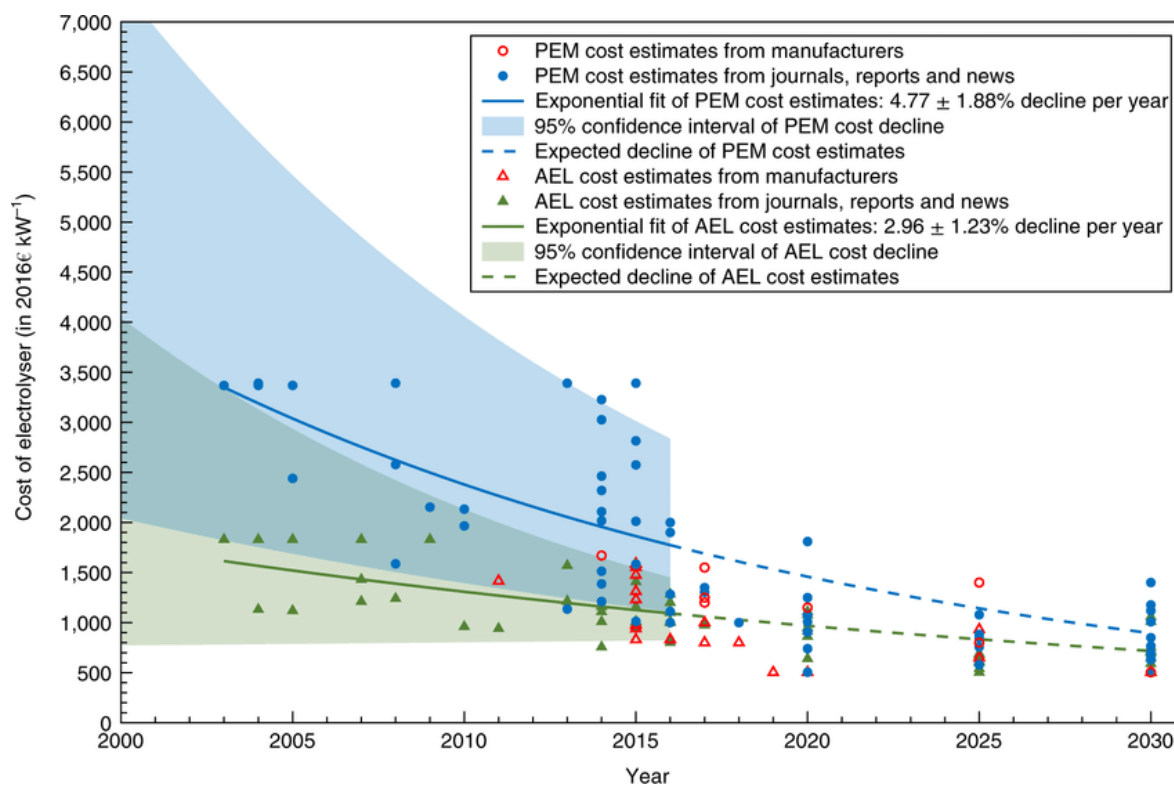


Figure 4-4: Cost development of electrolyzers over the years 200-2023 [4].

Learning curves can only be shown for a single energy storage technology, in the presented cases large hot water storage systems and electrolyzers. Any cost comparison between different storage technologies makes no sense. It is not possible to “compare” energy storage technology on this level. For any valid comparison, the actual application must be considered to determine the technical and economic operation conditions.

4.3 What is the Value of Energy Storage?

4.3.1 Energy Storage Provides a Variety of Benefits and Services

In our future energy system with higher shares of renewables, energy supply and demand must be balanced at all times and over all energy vectors. This means, energy has to be available where and when it is needed and in the form – electricity, heat/cold or fuels – it is needed. Energy storage stands for the shift in time: Matching supply and demand in time!

If we look at PV plants or wind turbines, we have a fluctuating supply, which does not match the demand patterns we have in the different demand sectors – electricity, heat and cold and mobility. Therefore we need energy storage to provide energy at times with high demand.

All energy storage solutions are able to store a certain amount of **energy**. This is called the energy storage capacity. Energy can be charged to and discharged from the energy storage at a certain **power** (energy/time). This charging or discharging power describes how fast the energy storage can be charged or discharged.

The actual application determines whether capacity or power is the most important parameter. For example for the seasonal storage of heat for heating purposes in the building sector, the amount of thermal energy is most important. For the example of ultra-fast charging infrastructure for E-mobility, the power-output needs to be maximised.

In general, energy storage solutions can provide very different benefits. Here are some examples:

- Electricity grid flexibility by electrical storage (e.g. pumped hydro) for the integration of renewable energy
- Reliability of power supply for crucial infrastructure by uninterruptable power supply (e.g. by batteries)
- Autarky of self-sufficient island systems for buildings, factories, or quarters
- Mobile power supply for EVs, mobile phones etc. by batteries or synthetic fuels

4.3.2 Business Case Development for Energy Storage

From the described benefits, a certain value can be derived. The actual value depends very much on the actual application and in the end from the question, how much would somebody pay for this specific benefit? If this target group can be identified, a solid business case might be developed.

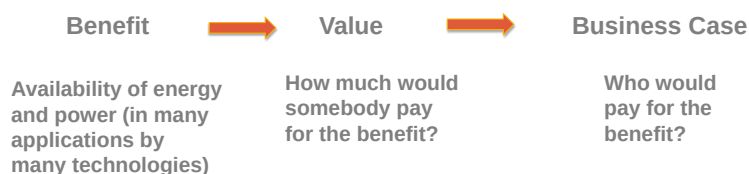


Figure 4-5: From benefit to business case.

Basically the three stages of energy storage – the charging, the storage itself and the discharging – are not equally suitable to create revenue streams. In most use cases the discharging, the supply of energy at a certain power is remunerated. In some cases also the charging, the uptake of energy at a certain rate, provides revenues. For example, if there is too much renewable electricity in the grid, negative power, provided by charging storage capacities, can be remunerated. However, such situations are probably not predictable enough to establish solid business cases.

Both revenue streams pay every time the storage is charged and discharged. The absolute amount of money depends on the number of charging/discharging cycles within a certain period. This shows that the expected cycle number for a specific application is an important parameter for the economic evaluation of energy storage systems. Figure 4-6 visualises these dependencies.

Metrics of Return on Investment | Energy Storage

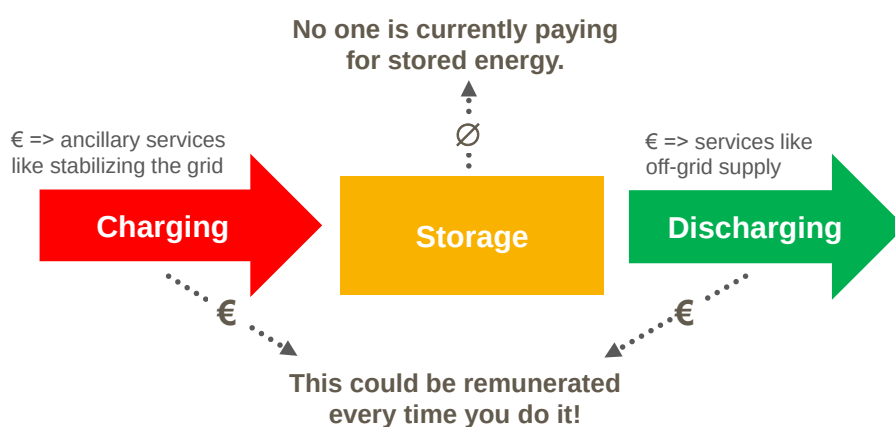


Figure 4-6: Metrics of return on investment in the case of energy storage systems.

An exception is the economic value of stored energy as such. This is the case when energy has to be stored for energy supply in a case of emergency or where uninterruptable power supply is necessary. In these use cases, high energy storage cost might be acceptable because storage might be the only solution. However, these might remain niche applications.

The connection between the number of charging and discharging cycles and the revenues, based on supplying energy from the storage, leads to a slow ROI for long-term storage (low cycle numbers per time) and a fast ROI for short-term storage (high cycle numbers per time). Or the other way around, if an application requires long-term storage, only very inexpensive energy storage technologies will be suitable. In the case of applications asking for short-term storage with many charging/discharging cycles, more expensive and advanced energy storage technologies might be used.

4.4 Economic Evaluation – Only possible in actual Applications

As stated before, there are many different energy storage technologies with different technical properties and cost structures. They can all provide a vast variety of benefits in all the different applications possible.

Necessary conditions for the economic evaluation of energy storage solutions are (among others):

- Energy storage cost (given by the storage technology)
- Energy storage properties required
 - Capacity
 - Power
 - Duration
 - Number of cycles (per time)
 - Cost of energy stored and/or supplied

The latter are determined by the actual application. Any economic evaluation is only possible looking at the most suitable storage technology with respect to an actual application. Only for a specific use case the cost and the revenue side can be evaluated. That is the reason why three different approaches to evaluate the economics of energy storage were developed in this Task.

4.5 References

- [1] Energy Storage TCP Strategic Plan 2026–2031. [Online] Available: <https://iea-es.org/publications/strategic-plan-2026-2031/>
- [2] Schmidt, O., Hawkes, A., Gambhir, A. et al. The future cost of electrical energy storage based on experience rates. *Nat Energy* 2, 17110 (2017)
- [3] T. Pauschinger et al., “Integrated Cost-effective Large-scale Thermal Energy Storage for Smart District Heating and Cooling 2 Document Information.” [Online]. Available: www.iea-dhc.org
- [4] Economics of converting renewable power to hydrogen, Gunther Glenk (University of Mannheim March 2019, *Nature Energy*, DOI:10.1038/s41560-019-0326-1

5 Key Performance Indicators for Energy Storage Economics

5.1 Introduction

As the global energy transition accelerates, energy storage systems (ESS) are becoming indispensable for enabling flexible, resilient, and decarbonised power systems. They serve as critical enablers of variable renewable energy integration, grid stability, load shifting, and electrification of end uses [5]. However, the economic viability of energy storage technologies varies widely across applications, geographies, and technology types. Capital costs remain high, revenue streams are complex, and market mechanisms are evolving making the economic assessment of ESS both essential and challenging [6]. A clear, consistent, and multi-dimensional evaluation framework is therefore needed to guide investment, policy, and system planning decisions [7].

The purpose of this chapter is to develop a comprehensive and theory-sound framework for evaluating the economic efficiency of ESSs. As energy storage (ES) technologies become increasingly critical for enabling renewable energy integration, enhancing grid reliability, and supporting decarbonisation, there is a growing need for standardised methods to assess their financial viability. This chapter sets out to identify quantitative and qualitative KPIs to assess the benefits of ESS and decision-making criteria that influence the economic evaluation of storage systems.

A central activity was the consolidation of existing knowledge through a literature review that spans a wide range of technologies (e.g., lithium-ion, flow batteries, thermal, mechanical), services (such as arbitrage, frequency regulation, and backup power), and deployment contexts (residential, commercial, and utility scale). This review was complemented by practical input from industrial partners and participating institutions within the Task 41 collaboration. In doing so, a harmonised set of methodologies and performance metrics that reflect both the cost and value dimensions of energy storage across various use cases is proposed.

In addition to reviewing established methods such as life cycle cost (LCC), levelised cost of storage (LCOS), and real options analysis (ROA), cf. Table 5-2, detailed economic indicators and key performance indicators (KPIs) were investigated. These include metrics that address not only traditional financial parameters, but also emerging factors such as environmental impact, geopolitical dependencies, and deployment responsiveness. One such KPI under development reflects the speed at which different energy storage technologies can be installed and scaled, which is of growing importance in the context of energy transition targets.

While the technical operation of energy storage systems was not the direct focus, technical characteristics such as round-trip efficiency, degradation rate, and lifetime remain essential inputs for an economic evaluation. These parameters must be integrated into cost models to ensure accuracy and comparability of economic outputs.

Figure 5-1 below illustrates the structured steps involved in performing an economic evaluation of energy storage systems. This serves as a conceptual basis for the methods and guidelines to be developed. As shown in Figure 5-1, the economic performance of an ES is assessed through defining the technical ES solution, cost and financial inputs and economic criteria goals, which are then analysed

in consolidation. This advises on the suitability of an ESS for a given application against the relevant decision-making criteria.

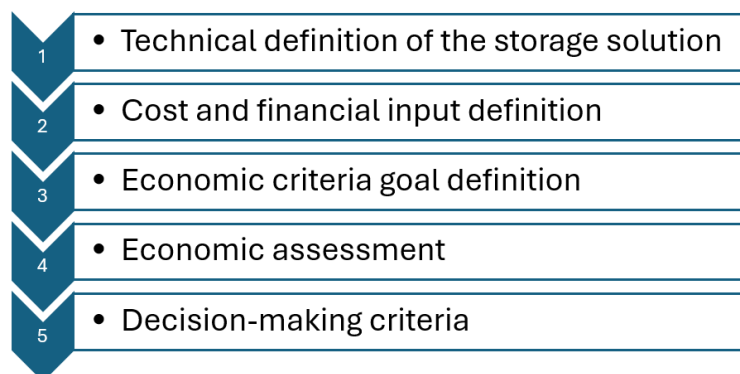


Figure 5-1 Methodology for economic performance assessment of energy storage systems.

To achieve its objectives, a set of targeted activities was followed, including:

- Conducting a comprehensive literature review and engaging stakeholders through surveys and interviews
- Developing advanced economic modelling approaches
- Defining key economic performance indicators

5.2 KPIs of energy storage

The value of energy storage in energy transition can be viewed from a system level, to ensure the true benefits are captured to energy systems as a whole. For this, relevant KPIs are identified, defined, and discussed herein. This includes both the traditional and conservative KPIs as well as novel, tailor-made KPIs, for a comprehensive performance analysis. These KPIs are categorised here considering technical, economic, environmental, and social aspects.

5.2.1 Technical KPIs

Technical performance is the foundational criterion for evaluating any energy storage system, regardless of its type (e.g., lithium-ion batteries, pumped hydro, compressed air, flywheels, thermal storage, or hydrogen). The key technical KPIs of relevance to ESS are presented in summary in Table 5-1.

Table 5-1: Common Technial KPIs of energy storage systems.

Technical KPI	Unit	Description
Energy density	kWh/kg (kWh/m ³)	Amount of energy stored per unit mass or volume
Power capacity	kW or MW	Maximum rate of energy discharge or intake.
Round-trip efficiency	%	Ratio of output energy to input energy.

Technical KPI	Unit	Description
Lifetime	Years or cycles	Duration for which the system performs effectively
Size and scale	kWh, m ² , m ³	Physical footprint and energy capacity
Charge/discharge Time	Seconds, minutes or hours	Time required to fully charge or discharge the system
Self-discharge rate	% per day/month	Proportion of energy lost while idling
Operating conditions	°C, bar, etc.	Determines the operating limits (temperature, pressure, etc.).
Response time	Milliseconds to minutes	Speed at which the system reacts to a charge/discharge signal
Safety thresholds	°C, bar, etc.	Tolerance against overheating, overpressure, fire, etc.

A key metric is energy density, typically measured in kilowatt hours per kilogram or per cubic meter (kWh/kg or kWh/m³). This indicator defines how much energy a system can store relative to its weight or volume, influencing its suitability for mobile (e.g., electric vehicles) or space-constrained stationary applications. Alongside this is power capacity, expressed in kilowatts (kW), which reflects the rate at which the system can deliver or absorb energy, a critical factor for generally for any ESS and particularly for grid services like frequency regulation or peak shaving.

Another core metric is efficiency, defined as the round-trip efficiency [%], which quantifies the energy retained through a full charge-discharge cycle. High-efficiency systems, such as lithium-ion batteries were reported with an average AC round-trip efficiency of 90% for power rates between 60 to 100% of the rated power (0.6–1.0 per unit) and 75–80% at 10% of the rated power (0.1 per unit) [8], are essential for applications where minimizing losses is critical. Lifetime, usually represented in years or as cycle life (number of charge/discharge cycles), indicates the durability of the storage system under operational conditions. For example, pumped hydro systems may last 50–100 years [9], whereas electrochemical batteries often have lifespans of 5–15 years (Li-ion battery systems’ state-of-health may decrease 1.37% per year with 119 full-cycle equivalents per year [8]).

Size and scale are also vital considerations—ranging from small residential systems of a few kWh to utility-scale installations exceeding MWh capacity, with physical footprints measured in square meters (m²) or cubic meters (m³). The operating conditions, including temperature and in some cases pressure, critically influence performance and safety. Lithium-ion batteries, for example, typically operate between 15–45 °C [10], while compressed air storage may involve high-pressure vessels (up to 100 bar [11]) and large underground caverns. These technical KPIs not only assist with design choices but also determine the suitability of a storage system for specific environments, applications, and grid requirements.

5.2.2 Economic KPIs

Economic performance indicators are vital for determining the financial viability and investment attractiveness of ESS. Among the most comprehensive measures is the LCC, expressed in currency unit, i.e. euros (€), which accounts for all costs across the system's lifetime—including capital expenditure (CapEx), operational expenditure (OpEx), maintenance, replacement, and disposal. Closely related is the LCOS, given in €/kWh, which distributes total lifetime costs over the energy delivered. A lower LCOS indicates better cost-effectiveness, especially in long-duration and high-utilization applications.

Two more granular cost metrics include the cost of installed power capacity (€/kW) and the cost of installed storage capacity (€/kWh). These distinguish between the expense of power (discharge rate) and energy (storage amount), which is important for sizing systems for applications like fast grid response (high kW) versus energy shifting (high kWh). Revenue (€) reflects total income generated from energy sales, grid services (e.g., frequency regulation, spinning reserve), or arbitrage (buying low, selling high), while cost saving or avoided cost (€) quantifies expenses prevented—such as reduced need for peak power generation plants, transmission upgrades, or curtailment of renewables. Curtailment costs—the expenses incurred when grid operators intentionally reduce renewable energy generation to maintain system stability—involve direct producer compensation, grid management fees, and the cost of purchasing replacement power. Payback time (years) indicates how quickly investment returns are realised through revenue and cost savings.

Table 5-2 shows common economic KPIs of energy storage systems. These economic KPIs form the basis for evaluating the financial feasibility and long-term viability of energy storage systems. Early-stage metrics such as CapEx and installed capacity costs guide technology selection and budgeting, while lifetime indicators like LCC, LCOS, and O&M costs assess sustained performance. Profitability measures including NPV, IRR, and ROI inform investment decisions and policy design.

Table 5-2: Common economic KPIs of energy storage systems.

Economic KPI	Unit	Description
Investment cost / Capital expenditure (CapEx)	€	The upfront amount invested to design, build and commission the facility
Life cycle cost (LCC)	€	Total cost over the system's full lifetime
Levelised cost of storage	€/kWh	Lifetime cost per unit of energy discharged
Installed power capacity cost	€/kW	Cost per unit of discharge power
Installed storage capacity cost	€/kWh	Cost per unit of installed energy storage capacity
CapEx per storage volume	€/m ³ & €/m ²	The investment cost per unit space or area, for thermal energy storage and other space-sensitive technology
Revenue	€	Total income and/or cost savings brought by the energy storage
Payback (PB) time	Years	Time needed to recover the investment via revenue or cost savings
Net present value (NPV)	€	The value of the energy storage cash flow is the sum of the present value of all the future cash flows that the storage will generate
Internal rate of return (IRR)	%	A discount rate where NPV equals to zero
Return on investment (ROI)	%	Ratio of net gain to total cost
Operational & maintenance (O&M) costs / Operational expenditure (OpEx)	€/year or €/cycle	Recurrent costs to keep the system functional, including inspections, repairs, and replacement

5.2.3 Environmental KPIs

Environmental KPIs assess the ecological and human health impact of energy storage systems across their entire life cycle - from raw material extraction and manufacturing to operation, disposal, or recycling as Figure 5-2 shows. These indicators help guide sustainable decision-making, policy compliance, and corporate environmental, social, and governance (ESG) reporting.

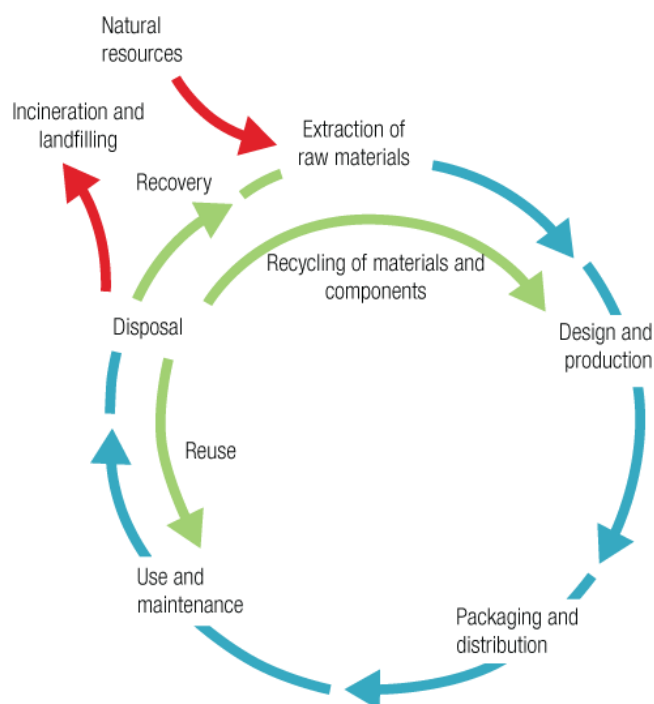


Figure 5-2: A typical product lifecycle diagram [12].

A key metric is life cycle greenhouse gas (GHG) emissions, typically measured in kg or tCO₂e per kWh delivered. This considers emissions from raw materials (e.g., lithium mining), manufacturing (e.g., energy-intensive electrode production), usage (if fossil grid power is used), and end-of-life treatment. Complementing this is the ozone depletion potential, which measures how much a material or process contributes to ozone layer damage, often expressed in kg CFC-11 equivalents.

Terrestrial acidification (e.g., SO₂ emissions) and ecotoxicity assess impacts on soil and water ecosystems, especially from heavy metals, sulphur compounds, or toxic leachates from battery waste. Relatedly, ecosystem impact evaluates land use change, habitat disruption (e.g., for pumped hydro), and biodiversity loss, using units like potentially disappeared fraction of species or qualitative severity scales.

Human Health Impacts encompass several risk areas:

- Toxicity (e.g., exposure to cadmium or cobalt),
- Radiation (for nuclear-based storage or material sourcing),
- Air quality degradation (from combustion-based charging or manufacturing), and
- Fire/explosion risk

Resource-related metrics include water use (litres/kWh), important for thermal systems or those requiring cooling, and the consumption of renewable vs. non-renewable resources, such as fossil fuels, rare earth elements, fossil-derived solvents, or mined metals. These are quantified using abiotic resource depletion indicators.

The environmental KPIs presented in Table 5-3 provide an assessment of the ecological footprint and

human health impacts of energy storage systems across their life cycle. Metrics such as life cycle GHG emissions, ozone depletion potential, terrestrial acidification, and ecotoxicity quantify global and local environmental burdens, while indicators like water use and resource depletion highlight pressures on critical resources. Safety and health related measures, including human toxicity potential, flammability risk, and air quality degradation, address operational hazards and societal impacts.

Table 5-3: Environmental KPIs of energy storage systems.

Environmental KPI	Unit	Description
Life cycle GHG emissions	tCO ₂ e	Total greenhouse gases emitted across production, use, and disposal
Ozone depletion potential	kg CFC-11 eq.	Impact of refrigerants, solvents, and materials on stratospheric ozone
Terrestrial acidification	kg SO ₂ eq.	Acidifying emissions affecting soils and freshwater systems
Ecotoxicity	Comparative toxic unit - environment	Harm to aquatic and terrestrial life due to leachates, metals, etc.
Ecosystem impact	Potentially disappeared fraction or qualitative	Biodiversity loss, habitat disruption, land use change
Human toxicity potential	Comparative toxic unit – human	Long-term health effects of chemical exposure from system materials
Flammability and fire risk	Severity rating	Probability of combustion or explosion under failure
Air quality degradation	PM _{2.5} (particulate matter ≤2.5 µm), NO _x , etc.	Particulate matter and other emissions affecting respiratory health
Radiation impact	Sv or mSv	Relevant to systems involving radioactive components or regions
Water use	Litres	Water required across lifecycle stages
Resource depletion, non-renewable	kg Sb eq. (antimony equivalent)	Rare and finite material use (e.g., lithium, cobalt, graphite)
Resource use, renewable	MJ	Energy or material inputs from renewables

5.2.4 Social KPIs

The deployment of ESS has far-reaching social implications that extend beyond technical and economic performance. Evaluating social indicators is essential for ensuring that storage technologies contribute to equitable, sustainable, and publicly supported energy transitions. Social indicators help capture the societal value, community alignment, and public perception of ESS projects, all of which are critical to long-term success and acceptance.

Table 5-4 summarises the key social KPIs relevant to ESS by grouping them into measurable categories. It highlights core metrics such as job creation, energy access, emission reduction, and community benefits, alongside qualitative measures like public awareness, aesthetics, and stakeholder engagement. These indicators provide a way to evaluate both tangible and intangible social impacts, supporting decision-making processes and enabling the comparison of ESS projects in different contexts.

Table 5-4: Social KPIs of energy storage systems.

Social KPI	Example metrics
Quality of life	Outage reduction, service reliability, energy access
Community impact	Local job creation, tax base improvement, co-benefits
Land use/noise/visual	Community complaints, buffer zones, aesthetics feedback
Public awareness	Participation in consultations, awareness surveys
Public acceptance	Support levels, NIMBY ¹ opposition, project delays
Sustainability impact	Alignment with SDGs ² , emissions avoided, local support

ESS can positively impact quality of life, especially in communities vulnerable to outages or with unstable grid access. By enabling more reliable energy supply, particularly in rural or remote areas, storage supports health, education, and economic opportunity. In urban settings, it can facilitate cleaner air and reduce exposure to fossil-fuelled peaking power plants. Localised storage deployment can bring direct benefits to communities, such as increased energy autonomy or improved service reliability. More importantly, job creation during installation, operation, and maintenance phases can stimulate local economies. In cases where storage is co-located with renewables, communities may benefit from shared revenue models or energy cost reductions. While generally more compact than energy generation infrastructure, ESS can have impacts on land use, acoustic, and visual aspects depending on size and setting. For example, large battery installations may require fire safety buffers and create visual intrusion in residential or scenic areas, though lower land use/visual intrusion for compact units. Noise emissions from cooling systems and inverters must be managed, particularly for installations near sensitive receptors (e.g., schools, hospitals, homes among others).

Public awareness of energy storage remains relatively low compared to other clean energy technologies. Transparent communication, participatory planning, and educational outreach are vital for improving public acceptance, particularly when storage is paired with community solar or municipal energy programs. Acceptance is higher when projects align with local values, promote sustainability,

¹ "Not In My Backyard", terminology used since the 1980's for opposition by residents to proposed developments in local neighborhood, even if perceived as beneficial

² "Sustainable Development Goals" is composed of 17 goals adopted by the United Nations in 2015 for sustainable development intended to be achieved by 2030

and demonstrate tangible benefits. ESS is increasingly perceived as an enabler of decarbonisation, which enhances public support for climate action. Projects that are well-communicated and aligned with broader sustainability goals can foster environmental stewardship, particularly among younger and climate-conscious demographics. Social indicators in this category include metrics such as community engagement levels and media sentiment analysis.

Social KPIs were not a primary focus of Task 41, which concentrated mainly on the technical and economic performance of energy storage systems. This focus reflects the objective of the Task to assess storage technologies using quantifiable parameters directly related to system performance, costs, and economic viability. Social KPIs are generally more context-dependent and require different assessment approaches. Nevertheless, they can complement technical and economic KPIs when evaluating energy storage systems from a broader sustainability perspective.

5.3 KPIs for evaluating energy storage economics

The technical, economic, environmental, and social KPIs presented in section 5.2 form the foundation for the methods described in this section. Each category contributes essential input parameters and evaluation criteria. Together, these dimensions ensure that the economic evaluation of energy storage is holistic, therefore, reflecting not only direct financial outcomes but also the broader system, environmental, and social contexts in which the technology operates.

5.3.1 Cost components of energy storage system

In evaluating the economics of energy storage (systems), the primary components considered include capital costs, installation costs, operational costs (such as energy usage, labour, and software management), maintenance costs, replacement costs due to degradation (e.g., battery replacements), salvage value at the end of life, and decommissioning or disposal costs. Each of these cost elements is discounted over time to reflect the time value of money using a discount rate. The structure and definitions of these components are based on internationally recognised standards such as ISO 15686-5:2017 for life-cycle costing [13] and the U.S. NIST Handbook 135 for federal infrastructure financial analysis [14]. Specific adaptations for energy storage applications are informed by academic literature, particularly the comparative work by Zakeri and Syri [15], and practical industry guidelines like Lazard's LCOS reports [16]. Together, these references establish a standardised yet energy-storage-tailored approach to calculate the main economic profile of energy storage projects as listed in equations (5-1) to (5-4).

Capital cost, C_{cap} , i.e. capital expenditure (CapEx) in equation (5-1) refers to the upfront, overnight installed cost of the system's equipment and other associated costs ([17], [18]). This includes the cost of storage hardware, $C_{equipment}$, e.g., battery packs, tanks, flywheels, power conversion systems (inverters, turbines, etc.), balance-of-plant components, as well as the cost of engineering design, $C_{design\ and\ engineering}$, cost of permitting, $C_{initial\ permits}$, and other development costs,

$$C_{cap} = C_{equipment} + C_{initial\ permits} + C_{design\ and\ engineering} \quad (5-1)$$

Installation cost, C_{inst} , in equation (5-2) covers the on-site implementation expenses that are not part of the core equipment purchase [17]. This includes site preparation for civil works and foundations and so on $C_{\text{site preparation}}$; construction labour, C_{labor} ; and system integration, wiring related to grid interconnection, $C_{\text{connection to grid}}$, e.g., transformers, switchgear, connection fees

$$C_{\text{inst}} = C_{\text{site preparation}} + C_{\text{labor}} + C_{\text{connection to grid}} \quad (5-2)$$

Operational costs at year t , $C_{\text{op\&m}}(t)$, i.e. operational expenditure (OpEx) in equation (5-3) is the yearly costs including: the charging cost, $C_{\text{energy}}(t)$, which is important for market arbitrage and to be offset by revenue from discharge; maintenance cost for routine part replacements and repairs due to failures or issues $C_{\text{maint}}(t)$. For instance, battery replacements at scheduled lifetime for battery energy storage systems, heat pump/turbomachinery mid-life overhaul and replacement for pumping related thermal energy storages ([19], [20]); personnel cost for monitoring, control, and security, $C_{\text{labor}}(t)$; as well as cost for energy management system software and data management, $C_{\text{software}}(t)$, ([17], [21], [22]),

$$C_{\text{op\&m}}(t) = C_{\text{energy}}(t) + C_{\text{maint}}(t) + C_{\text{labor}}(t) + C_{\text{software}}(t) \quad (5-3)$$

Decommissioning/disposal costs at end of life (year n), $C_{\text{decom}}(n)$ include costs to uninstall, transport, recycle/dispose of the system, which is part of the life-cycle cost ([23], [24], [25]),

$$C_{\text{decom}}(n) = \frac{C_{\text{disposal_and_removal}}}{(1+r)^n} \quad (5-4)$$

Salvage value, S_{end} , is the residual value at end-of-life (year n), by resale of EV batteries for stationary storage applications [26], resale of materials such as metals, electrolyte, steel, etc. and discounted to present value ([24], [27], [28]),

$$S_{\text{end}} = \frac{C_{\text{residual}}}{(1+r)^n} \quad (5-5)$$

5.3.2 Life-cycle cost and levelised cost of storage

LCC analysis is a financial evaluation method that sums all the costs associated with a system over its entire life cycle — from initial capital investment to operation, maintenance, and decommissioning costs. This cost indicator is crucial for energy storage systems due to high upfront investment cost, and economic viability depends heavily on future performance, degradation rates, and O&M (operations and maintenance) expenses. The LCC of ESS can be expressed as

$$\text{LCC} = C_{\text{cap}} + C_{\text{inst}} + \sum_{t=1}^n \frac{C_{\text{op\&m}}(t)}{(1+r)^t} + C_{\text{decom}}(n) - S_{\text{end}} \quad (5-6)$$

The LCC analysis for energy storage begins by defining system boundaries—technology type, scale, and

application—as shown in Zakeri and Syri [15]. It then involves estimating all cost elements, including CAPEX, O&M, replacement, and decommissioning costs. Luo et al. [29] further highlights the importance of including insurance and compliance costs. The analysis typically spans over the system’s usable life, with costs discounted—commonly at 5–10% as recommended by Schmidt et al. [30], to compute the net present value (NPV). Technologies can then be compared using LCOS (€/MWh), which enables benchmarking, as seen in Lazard’s LCOS Version 6.0 [12].

LCC’s strengths lie in its comprehensive accounting of lifecycle costs and its ability to support comparison across technologies, e.g., high-efficiency vs. lower-cost systems, demonstrated by Lazard [16] and Zakeri & Syri [15]. It also aids investment and policy decisions. However, it is highly sensitive to assumptions such as lifespan and discount rates ([29], [30]), and often excludes unpredictable future costs and non-monetary benefits like grid resilience and emissions reduction, as noted by Denholm et al. [31].

LCOS is a common standardised metric used to evaluate and compare the cost-effectiveness of different ESS [25]. It expresses the total lifetime costs divided by the total energy discharged over that lifetime, giving a cost per unit of electrical/thermal energy delivered. Compared to levelised cost of energy (LCOE) used in electricity production [32], which tells what price to sell to be profitable over the lifetime, LCOS quantifies the average spread between charge and discharge prices that needs to exist for profitability. Balliet et al. [27] compared four definitions of LCOS, which are Lazard³, DOE ESGC⁴, ARPA-E DAYS⁵ formulations and a proposed formulation. All definitions aim to express the average cost added by energy discharged. The Lazard and DOE ESGC models include the cost of charging electricity, focusing solely on storage inefficiencies like round-trip energy losses, which can misrepresent storage-specific costs, and the proposed definition excludes it. The ARPA-E DAYS model is the simplest, using a closed-form equation suitable for early-stage comparisons, but lacks granularity. In contrast, the proposed model by Balliet et al. incorporates a comprehensive lifecycle analysis, accounting for capital costs, O&M, financing, taxes, depreciation, and residual values. This makes it more complex but also more precise and comparable. The key difference lies in which costs are included and how deeply the project’s full lifecycle is modelled, with the proposed definition offering a standardised framework for both industry and research.

$$\text{LCOS} = \frac{\text{LCC}}{\text{Total lifetime energy delivered (discounted)}} = \frac{\text{LCC}}{\sum_{t=1}^n \frac{E(t)}{(1+r)^t}} \quad (5-7)$$

A methodological step in LCC analysis and LCOS for ESS can be synthesised from [15], [16], and [30] which can be used in LCOS assessments:

³ A global financial advisory and asset management firm

⁴ U.S. Department of Energy, Energy Storage Grand Challenge

⁵ Part of the U.S. DOE, Duration Addition to Electricity Storage

- 1) Define system boundaries for comparison across storage types. Emphasise the importance of including installation, replacement, and technology-specific degradation
- 2) Estimate cost elements as described in equations (5-1) to (5-4)
- 3) Set analysis period used timeframes based on storage lifespans (e.g. 10–30 years), essential for discounted cash flow
- 4) Select discount rate depending on risk and financing structure
- 5) Calculate LCC
- 6) Compare using LCOS per MWh across technologies.

Note that technical simulation which calculates life-cycle energy charged and discharged and behaviour of the storage in the system is also required in this procedure for calculated LCC and LCOS. This structure provides comparability across technologies and supports investment decisions by standardizing how economic performance is evaluated over the storage system's full life cycle.

5.3.3 Revenues and revenue stacking

Revenue stacking (also known as service stacking) refers to an economic strategy where an energy storage system delivers multiple services that can be monetised across various electricity markets or customer applications, thereby accumulating multiple revenue streams [33]. This is critical because energy arbitrage alone (buying low, selling high) often fails to justify the high capital cost of storage [33]. Common services that can be stacked are presented as follows with annual value:

- 1) Energy arbitrage (simplified from [34]),

$$\text{Revenue}_{\text{arbitrage}} = \sum_{h=1}^{\text{hours in a year}} (P_h^{\text{sel}} \cdot E_h^{\text{out}} - P_h^{\text{buy}} \cdot E_h^{\text{in}}) \quad (5-8)$$

where P_h^{sel} is price of energy at hour h during discharge, P_h^{buy} is price at hour h during charge, E_h^{out} , E_h^{in} are energy discharged/charged at hour h.

- 2) Frequency regulation with a market-based scheme,

$$\text{Revenue}_{\text{reg}} = \sum_{h=1}^{\text{hours in a year}} C_h^{\text{reg}} \cdot Q_h^{\text{reg}} \quad (5-9)$$

where C_h^{reg} is market clearing price for regulation capacity, Q_h^{reg} is quantity of capacity/power reserved for regulation. Agostini et al. [35] compared the market-based scheme with a cost-based scheme for frequency regulation.

- 3) Participation in spinning reserve Revenue_{spin} and c where P_h^{res} is reserved capacity in kW and C_h^{r} the price of reserved capacity in currency/kW. The same equation applies for calculating capacity market ([36], [37]),

$$\text{Revenue}_{spin} = \sum_{h=1}^{\text{hours in a year}} P_h^{\text{res}} \cdot C_h^r \quad (5-10)$$

- 4) Peak shaving saving on a top-up device, for instance, a fossil fuel generator and an electrical heater, as in Equation (5-11).

$$\text{Revenue}_{\text{peak shaving}} = \sum_{h=1}^{\text{hours in a year}} C_h^{\text{topup}} \cdot \Delta Q_h^{\text{shaved}} \quad (5-11)$$

Where C_h^{topup} is the cost of top up device €/kWh in hour h, $\Delta Q_h^{\text{shaved}}$ is the amount of energy peak shaved in kWh in hour h.

- 5) Backup power/resilience based on customer damage function. Grid resilience can be defined as “The ability of a power system and its components to withstand and adapt to disruptions and rapidly recover from them” [38] and “The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event” [39].

$$\text{Revenue}_{\text{resilience}} = VoLL \cdot P_{\text{backup}} \cdot T_{\text{backup}} \quad (5-12)$$

Where $VoLL$ is value of lost load in €/kWh as defined by through a more cost-effective design of the surrounding energy system. [40], P_{backup} load in kW and T_{backup} duration in hour during critical period. Ghodeswar et al. [41] also studied the backup investment using interruption cost estimate and willingness-to-pay (e.g. to avoid hypothetical power interruptions).

The annual total revenue brought by an ESS can be calculated by summing up all these stackings:

$$\text{Revenue}_{\text{total}} = \text{Revenue}_{\text{arbitrage}} + \text{Revenue}_{\text{reg}} + \dots + \text{Revenue}_{\text{resilience}} \quad (5-13)$$

The life-cycle revenue (LCR) can be calculated as:

$$LCR = \sum_{t=1}^N \frac{\text{Revenue}_{\text{total}}(t)}{(1+r)^t} \quad (5-14)$$

5.3.4 Net present value (NPV), payback (PB) time, and return on investment (ROI)

Payback (PB) time [42] refers to the period required for an ESS to recover its initial capital investment C_{cap} through the net financial benefits $\text{Revenue}_{\text{total}}$ it generates. PB time is often complemented by

discounted cash flow methods or NPV analysis [43].

$$PB = \frac{\text{Initial investment cost}}{\text{Annual revenue}} = \frac{C_{cap}}{\text{Revenue}_{total}} \quad (5-15)$$

The financial viability of an energy storage project is typically evaluated using NPV and return on investment (ROI) [44]. These two metrics capture the absolute profitability and the relative efficiency of the investment, respectively.

$$NPV = \sum_{t=0}^n \frac{\text{Cash Flow}_t}{(1+r)^t} = \sum_{t=0}^n \frac{\text{Revenue}_{total}(t) - \text{Cost}_{total}(t)}{(1+r)^t} \quad (5-16)$$

where Cash Flow_t is the net cash flow in year t (total revenues minus costs), t is the project lifetime in years. The NPV method discounts future revenues and costs to present value terms to assess whether the project creates or destroys value. A positive NPV indicates that the present value of revenues exceeds the present value of costs, implying profitability. A negative NPV suggests the project is financially unviable. To determine the break-even point, the internal rate of return (IRR) is the value of r which is given by:

$$0 = \sum_{t=0}^n \frac{\text{Cash Flow}_t}{(1+r)^t} \quad (5-17)$$

Another useful metric is the ROI [45], particularly in comparative or policy evaluation contexts. For energy storage systems, the common definition of ROI can be calculated as,

$$ROI = \frac{\text{Total net profit}}{\text{Total discounted cost}} = \frac{LCR - LCC}{LCC} \quad (5-18)$$

A positive ROI in an ES project demonstrates financial viability, meaning the system lifetime revenues exceed its total costs. Conversely, a negative ROI indicates that revenues fall short of covering capital, operational, and replacement expenses, posing investment risks.

5.3.5 Real option analysis (ROA)

In evaluating energy infrastructure projects—particularly those related to renewable generation and storage—decision makers traditionally rely on methods such as NPV, LCC and LCOS. These methods assume deterministic cash flows and immediate commitment of capital, undervaluing projects that operate in environments of high uncertainty and policy volatility. To overcome these limitations, the application of ROA ([46], [47], [48]) has emerged as a superior approach, capturing the value of managerial flexibility in the face of changing market dynamics.

Several comparative case studies bring compelling evidence of ROA's advantages. Locatelli et al. [47] applied ROA to ESS, specifically examining pumped hydro storage and compressed air energy storage

systems in the UK market. Traditional NPV in this context showed weak or even negative returns, leading to a pessimistic outlook. However, when ROA was applied incorporating multiple real options such as the option to delay investment, to divide construction phase, and to adapt based on future price signals, the economic outlook improved considerably. The authors used Monte Carlo simulations and scenario modelling to assess risk factors like electricity price spread, natural gas costs, and construction delays. Their findings revealed that ROA not only captures value from market flexibility but also helps identify policy thresholds such as the level of subsidy needed to trigger investment viability. Even in projects with initially poor traditional metrics, ROA uncovered hidden values that could shift an investment from unviable to bankable under alternative scenarios.

Locatelli et al. [47] identify specific ROAs as presented in Table 5-5, that are of interest for ESS analyses, to capture these otherwise hidden values.

Table 5-5: Real option types from Locatelli et al. [47]

Real option type	Definition
Option to wait to invest	Delay investment until market or technical conditions improve. For situations where it is more profitable to postpone the project than invest immediately.
Option to build	Decide whether to proceed with building after conducting detailed design. For filtering out poor scenarios
Option to wait to build	Further delay even after design, in hope of better CAPEX or market conditions. Limited benefits, unless major cost reductions or policy shifts occur

For ROA's utility in renewable power plants, Fabianek et al. [46] used a sequential real options model to assess hydrogen-based power-to-power systems in Germany and California. The investment, structured in three phases, wind, solar, and electrolyzers, showed negative NPV under current conditions, but ROA revealed strategic value in starting with wind and delaying further stages until market conditions improve. This approach accounted for carbon pricing, fuel costs, and tech evolution. Similarly, Santos et al. [48] applied ROA to a mini-hydro project in Portugal, where traditional NPV showed low returns of € 51,371, but ROA, through boosted value to € 433,659 by capturing the option to defer investment. Both studies demonstrate ROA's strength in aligning with flexible, real-world investment behaviour under uncertainty.

Table 5-6 summarises the main differences between the traditional NPV approach and Real Options Analysis (ROA) when assessing energy storage investments. Unlike the traditional method, which assumes deterministic inputs and discounts or ignores uncertainty, ROA explicitly incorporates stochastic variables (e.g., price volatility) and provides an "expanded NPV" that captures the additional value of managerial flexibility under uncertainty.

Table 5-6: Key comparison ROA and traditional method ([49], [50], [51]).

Criteria	Traditional method	ROA
Market assumption	Deterministic, fixed inputs	Stochastic, flexible, forward-looking
Treatment of uncertainty	Discounted or assumed	Explicitly modelled (e.g., volatility)
Output	NPV	Expanded NPV including option value

5.3.6 Experience curve and future forecast

Experience curve modelling is a predictive economic tool that quantifies how the unit cost of a technology decreases as its cumulative installed capacity increases. Originally developed for the aerospace industry, this approach assumes a "learning-by-doing" effect and has since been applied widely in energy technology forecasting. A core metric in this model is the learning rate (LR), which reflects the percentage cost reduction that occurs each time cumulative production doubles [52]. The fundamental form of the single factor experience curve is [52] $Y = aX^b$, where Y is cost per unit, a is cumulative installed capacity, X is initial cost, b is learning coefficient. The learning rate is derived using $LR = 1 - 2^b$.

A study by Zhang et al. [53] in 2024 focuses on electrochemical energy storage systems in China and fits empirical data using the single factor experience curve model. Their analysis, based on battery system cost and installed capacity data from 2013 to 2023, estimated the learning rate of China's EES sector at 13% ($\pm 2\%$). For comparison, they also estimated learning rates for electric battery packs to be 15% ($\pm 3\%$) and consumer electronics battery modules to be 11% ($\pm 3\%$). The study also confirms that the cost of these electrochemical EES systems in China fell by approximately 40% between 2017 and 2023, driven largely by industrial learning and production scaling. The research forecasts that by 2030, under optimistic assumptions (high LR), the cost per kilowatt-hour of EES will decline to \$71–\$78, and further down to \$60–\$65/kWh by 2035. The LCOS is also affected by learning. Zhang et al. [53] project, as shown in Figure 5-3, that LCOS will reach \$0.045–\$0.077/kWh by 2035 under medium learning scenarios, approaching or surpassing the economic parity threshold (the point at which it becomes economically competitive with its alternative without subsidies or incentives) of \$0.057/kWh, deemed competitive in China's energy market.

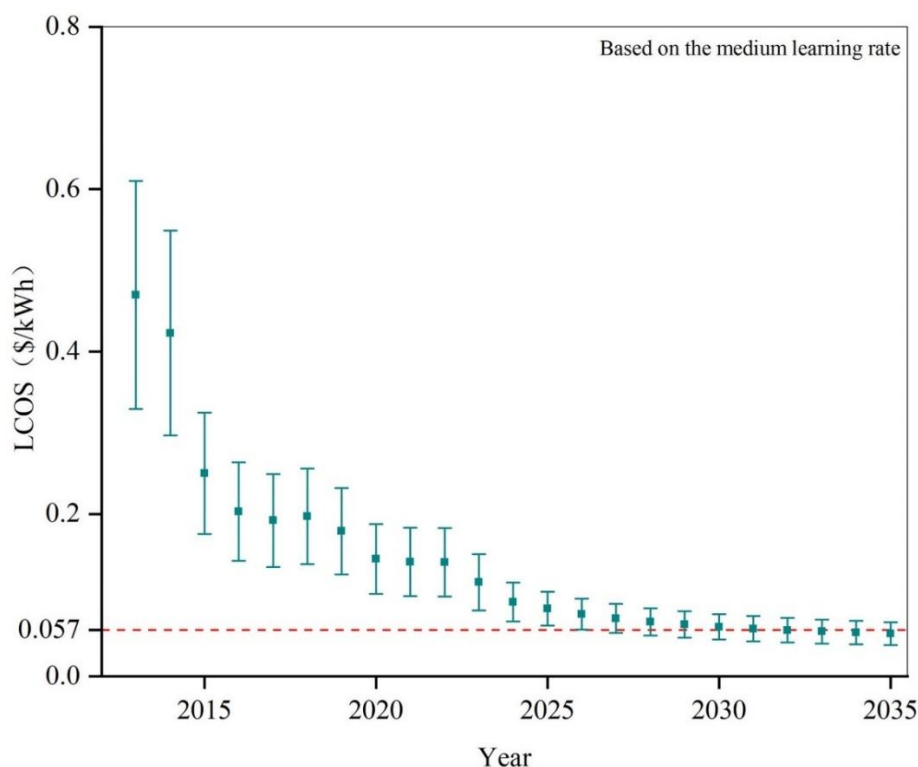


Figure 5-3: Prediction of the electrochemical storage LCOS in China [53].

While multi-factor models exist incorporating e.g. research and development (R&D) effects, policy interventions, and material cost changes, this study supports the use of a single factor model due to data availability constraints and model simplicity. As Rubin [54] argues, single-factor models provide reasonable accuracy for policy scenario modelling when detailed R&D and cost breakdowns are not fully observable.

5.4 Contextual dimensions of ES economic KPIs

The estimation and interpretation of the many economic KPIs for assessing ES depends on the various contexts they are assessed from. For instance, the revenue streams are different between different ES technologies, the value, suitability and benefits from ES differ between different stakeholders and applications. These aspects are discussed here in detail.

5.4.1 Concerning the revenue stream of different storage technologies

Compared with other types of energy storage, electrochemical storage systems, commonly lithium-ion and flow batteries, generate their revenues from stackable power-market services. The main

revenue is from energy arbitrage and some other streams [55], including:

- (1) Electricity price arbitrage, where stored energy is bought at low prices during off-peak periods and sold at higher prices during peak demand.
- (2) Ancillary service arbitrage, by providing fast-response frequency and reserve capacity to grid operators.
- (3) Grid investment deferral, through peak shaving to delay or avoid network upgrades.
- (4) Renewable energy integration, capturing value by smoothing the output of wind and solar farms.
- (5) Black start services, offering backup power to restart the grid after outages.
- (6) Carbon emissions reduction, earning credits as stored renewable energy displaces fossil generation.

Mechanical energy storage technologies, including pumped-hydro storage (PHS), compressed-air energy storage (CAES), flywheels, and emerging gravity-based technologies, gain revenues like batteries by electricity arbitrage through pumping water or compressing air off-peak and releasing power at peak pricing, over multi-hour or even seasonal cycles. Large-scale pumped hydro and CAES are providers of spinning reserves, frequency regulation, and black-start services, drawing hefty capacity payments ([56], [57]). While smaller flywheels excel at sub-second frequency support [58]. The main revenues of mechanical storage are:

- (1) Electricity arbitrage, pump-and-turbine or compress-and-expand cycles buy off-peak power and sell at peak, over multi-hour to seasonal durations.
- (2) Spinning & non-spinning reserves, large-scale PHS and CAES earn capacity payments for maintaining ready megawatts, plus fast-response frequency regulation fees.
- (3) Grid-upgrade deferral, discharging into congested nodes defers T&D investments as electrochemical batteries.
- (4) Seasonal storage, as a seasonal shift of PHS.
- (5) Frequency stabilization, which flywheels prices for sub-second power quality, uninterrupted power supply (UPS), and frequency stabilization despite limited kWh capacity.

Thermal energy storage (TES) systems, ranging from molten-salt tanks in concentrated solar plants to water and phase change material thermal energy storage, yield revenue mainly through cost avoidance rather than direct electricity/thermal energy kWh sales. The following revenue streams are

commonly found in thermal energy storage projects [59]:

- (1) Thermal arbitrage, charging by heating or cooling during off-peak or low-tariff periods and discharging when fuel or electricity costs are high.
- (2) Peak load shaving in commercial HVAC systems, where TES tanks reduce peak thermal demand billed on a kW level basis.
- (3) Process-heat contracts, as industrial users pay a contracted fee for guaranteed steam or hot water delivery, turning stored thermal capacity into a steady service revenue.
- (4) Capacity reservation fees, where district-heating/cooling networks reserve tank capacity for peak-hour delivery, analogous to grid-capacity payments.
- (5) Firm renewable dispatch, where in CSP plants, molten-salt storage enables 24-hour power sales at premium evening rates, substantially increasing capacity factors and revenues.

Hydrogen as energy storage offers the following revenue streams [60]:

- (1) Energy arbitrage / energy shifting – Hydrogen is produced when electricity prices are low or surplus renewable electricity is available, stored, and later converted back to electricity when prices are higher.
- (2) Balancing & frequency-control services – Electrolyzers and hydrogen-to-power units can rapidly adjust their power consumption or generation to help balance short-term fluctuations in electricity supply and demand.
- (3) Capacity / reserve provision – Stored hydrogen can provide dispatchable energy during periods of peak demand or low renewable generation and can therefore contribute to capacity and reserve markets.
- (4) Congestion management & grid services – Electrolyzers can absorb electricity in regions or periods with grid congestion, while hydrogen-based generation can support the grid where additional power is needed.
- (5) Long-duration / seasonal energy supply – Hydrogen can store large amounts of energy over days, weeks, or seasons and make this energy available during prolonged periods of low renewable generation.

5.4.2 Concerning different stakeholders

The economic evaluation of ESS is inherently shaped by the perspectives, priorities, and decision-making criteria of different stakeholders. These include utilities, regulators, system operators, industrial users, residential customers, developers, investors, and policymakers. Each group interprets the value and viability of storage through a distinct lens based on their objectives, constraints, and risk appetites. As a result, a single ESS project may be deemed economically attractive by one stakeholder but unviable by another.

Utilities and TSOs assess ESS primarily in terms of grid reliability, deferral of capital investments, and system balancing services. Their economic decisions are driven by system-level cost savings such as avoided transmission upgrades, reduced peak demand charges, or enhanced frequency regulation. These actors often rely on system optimization models and focus on net system cost-benefit analysis,

which may include non-revenue value streams like increased hosting capacity/reduced curtailment for renewables or improved resilience [61]. Tools like PNNL's ESET™ and BSET are designed to help utilities model stacked-value applications across technical and market services [62].

Policymakers and regulators emphasise societal value, environmental externalities, and market fairness. Their perspective introduces non-market benefits such as GHG reductions, system resilience, and energy justice into economic evaluations. These stakeholders influence the economic feasibility of ESS through mechanisms like subsidies, carbon pricing, or performance standards. They often prioritise cost of GHG reduction (€/tCO₂e), deployment timelines, and alignment with strategic decarbonisation goals over direct financial returns. ROA is particularly useful for these actors, capturing the value of flexible deployment under policy uncertainty ([61], [63]).

Developers and financiers require project-level profitability assessments, typically using metrics like NPV, IRR, and ROI. They are sensitive to financing structures, capital costs, market access for revenue stacking, and regulatory risk. Developers tend to favour short to medium-term payback horizons and often discount longer-term system benefits. Their evaluation frameworks rely heavily on LCOS and stacked revenue models, with sensitivity analyses around electricity market volatility and capacity payments.

Large energy users evaluate storage primarily as a means to reduce operational costs and enhance reliability. Key decision factors include peak demand charge reduction, power quality improvement, emergency backup capability, and load shifting for time-of-use savings. These stakeholders typically require customised techno-economic assessments, with a focus on cost savings, operational integration, and resilience metrics like VoLL. While LCOS is relevant, these users may also demand scenario-based ROI models tied to outage frequency or tariff changes.

Residential users are highly sensitive to upfront costs, subsidy availability, and perceived energy independence. Their decision-making is influenced more by behavioural economics and non-financial benefits (e.g., self-sufficiency, environmental concern) than strict payback calculations. However, consumer-friendly tools like simple payback time, lifetime cost comparison, and annual bill savings remain key indicators. In this segment, perceived value can diverge from actual LCOS due to differing priorities and risk perceptions.

5.4.3 Concerning different energy storage applications

The economic and operational value of ESS is profoundly shaped by the specific domain in which they are deployed. Each application whether at the generation, transmission, distribution, customer, or ancillary service level—presents unique value streams, revenue mechanisms, and performance expectations. Understanding these distinctions is essential for accurate economic evaluation and appropriate technology selection.

ESS used in generation support and bulk energy storage plays a pivotal role in stabilizing large-scale electricity supply. These systems enable renewable integration by storing excess solar or wind power and discharging it during demand peaks. They are also used for load levelling, balancing supply-demand mismatches over daily or seasonal periods. Moreover, capacity firming, meaning consistent

and reliable supply of energy [64] ensuring consistent generation output, reducing the variability of renewables. The economic models in this context focus on long-duration storage, energy arbitrage, and system-wide cost optimization.

In transmission networks, ESS can help reduce congestion by temporarily absorbing energy when lines are overloaded and discharging it when conditions ease. This function provides congestion relief, which can prevent or delay costly infrastructure upgrades. Additionally, transmission deferral uses storage, supporting system stability without expanding physical grid infrastructure. These services are especially valued in regions with high renewable penetration and constrained transmission corridors.

At the distribution level, energy storage supports localised power management. One key function is voltage regulation, where ESS corrects voltage deviations caused by high rooftop solar penetration or fluctuating local demand. In terms of e.g. district heating and cooling, distributed TES can facilitate better grid dynamics management of thermal power distribution from supply to demand, when the grid capacity is limited [65]. Another is distribution deferral, where ESS delays or avoids investments in substations, transformers, or feeder lines. The economic evaluation here often relies on distribution-specific cost-benefit analysis and incorporates reliability metrics such as reduced outage duration.

For residential, commercial, or industrial customers, energy storage is deployed to enhance on-site energy efficiency and resilience. ESS is widely used for peak shaving, which lowers electricity costs by reducing usage during high-tariff periods. Demand charge reduction is another major driver in the commercial sector, minimizing utility fees based on peak consumption. Additionally, backup power provides reliability during grid outages, adding to a potential monetary value component. In these settings, evaluation metrics today focus on payback period, bill savings, and system autonomy.

Energy storage contributes significantly to ancillary services essential for real-time grid operations. These include frequency regulation, which stabilises short-term imbalances; voltage support, which maintains power quality; and spinning reserve, where ESS is ready to dispatch power instantly during system contingencies. These services are monetised in competitive electricity markets or through contracts with grid operators, with evaluation models centred on high-power responsiveness and rapid cycling economics.

Finally, ESS is also applied in non-commercial or specialised contexts, including research and development, pilot projects, micro grids, and university campuses. These deployments are designed to validate new technologies, explore regulatory models, or demonstrate integration strategies. Although they may not offer immediate economic returns, their strategic value lies in innovation, technology demonstration, data generation, and capacity building for broader adoption.

In conclusion, each application area imposes distinct economic, technical, social, and regulatory conditions. Tailoring the economic evaluation to the specific application is critical for accurately capturing value, informing technology choice, and supporting sound investment or policy decisions. A one-size-fits-all model is insufficient; instead, application-specific evaluation frameworks are essential for guiding energy storage deployment effectively.

5.5 Example calculations

The application of main KPIs discussed in the previous sections is exemplified herein, considering two example ESSs on TES.

5.5.1 Pit thermal energy storage (PTES), the Høje Taastrup Project, Denmark

PTES enables the capture of low-cost summer heat for use during winter peak demand, providing seasonal flexibility in district heating networks. The Høje Taastrup PTES, developed under the IEA-Energy Storage Task 39 [66] shown in Figure 5-4. The storage medium is water, with a total capacity of 3,300 MWh. It supports charge power up to 30 MW and discharge power up to 38 MW, designed for roughly 25–30 full cycles per year. Ownership is split equally between VEKS and Høje Taastrup Fjernvarme; VEKS covers maintenance costs while Høje Taastrup Fjernvarme handles daily operation. The pit is located adjacent to major transmission and distribution piping in Høje Taastrup, with an exchange building housing the hydraulic and measurement equipment.



Figure 5-4: Pit thermal energy storage in the Høje Taastrup Project, Denmark (Photo: Ioannis Sifnaios).

Peak discharge power reached 38 MW (1-hour max 20 MW, mean 7 MW), while charging peaked at 30 MW (1-hour max 29 MW, mean 11 MW). Weekly energy throughput varied seasonally, from approximately 800 MWh/week in winter up to 2,500 MWh/week in spring. Stored water temperatures ranged from 45 °C at the bottom during discharge to 89 °C at the fully charged top, with discharge temperatures between 70 and 90 °C. Over the first year, the facility achieved seasonal efficiency of about 87%, with monthly efficiencies between 85 and 92%. Long-term loss modelling projects roughly 700 MWh/year of heat loss after initial commissioning, corresponding to over 95% efficiency over eight years.

The project's economic KPIs are listed in Table 5-7, the facility reduces CO₂ emissions by about 9,000 t/year. Benefits are allocated among CHP plants, waste-to-energy, and peak-boiler operators, with shares ranging from 30 to 60%. A municipality-backed loan structure shares investment risk among stakeholders.

Table 5-7: Economic KPIs of the PTES from 2023 (IEA ES TCP Task41 expert meeting, Denmark [67]).

Economic KPIs	Value	Unit
CapEx	12.1	Million €
OpEx	0.23	Million €/year
Simple payback time	11.7	Year
IRR	7.5	%
Subsidies	1.7	Million €
Estimated operating profit	1	Million €/year

5.5.2 Phase change material (PCM) thermal energy storage in an office building, Sweden

A full-scale PCM thermal energy storage system using 7000 L of a salt-hydrate (SP11) within an 11,200 L external tank (shown in Figure 5-5) was installed in a multi-story office at Chalmers University in Gothenburg, Sweden. The storage is charged overnight by the district cooling network at about 8 °C and discharged during daytime peak hours via a capillary-tube heat exchanger to the air-handling unit. Over a typical day, the system provides 99 kWh of usable cooling, which is 36% of its 275 kWh nominal capacity. The measured PCM storage density is 46.5 kWh/m³, yet the useful material storage density is only 14.1 kWh/m³, yielding an overall system density of 8.84 kWh/m³. The installed system's total CapEx is 546,452 SEK (51,310 €), with 64.5% (352,462 SEK; 33,111 €) for PCM material and the remainder for the tank, heat exchanger, shipping, and installation [68].



Figure 5-5: "A working lab" (AWL) office building (a) and PCM TES installation located in the basement of AWL (b) [68].

Economic boundary conditions include time-dependent cooling tariffs and peak-power charges. Absorption-chiller cooling costs 0.15 SEK/kWh from April to October, and rises to 0.70 SEK/kWh in November and 1.00 SEK/kWh from December to March. Electric heat pumps at COP 2 - 2.5 incur 0.287 - 0.359 SEK/kWh. A monthly surcharge of 15.52 - 19.4 SEK/kW applies for peak demand, and auxiliary pumping consumes 19.2 kWh per cycle at 0.72 SEK/kWh [68].

Using currency values of 2020, a mixed-integer linear program optimised daily charge/discharge scheduling over a year's cooling demand to minimise total cost. For a single PCM unit, annual costs drop by 4.17%, mainly from an 8.19% reduction in peak-power charges and a 0.76% decrease in energy costs. In this specific case study, the main economic benefit is from lower peak-power charges rather than energy savings. To achieve a five-year payback under tariffs (taken from 2020), investment must not exceed 9,804 SEK per unit. Doubling the PCM density raises this threshold to 15,421 SEK (around 1,448 €). Thus, improvements in heat exchanger design and control strategies could boost usable capacity and acceptable investment limits [68].

5.6 Conclusions and Recommendations

Considering technical, economic, environmental, and societal KPIs, robust and comparable evaluation methods are essential for determining the value of ESS across diverse contexts. While today's KPIs provide a conservative baseline. Particularly concerning revenue stacking, the potential in monetizing benefits that exist can be quantified but are not yet completely included in the business models. The benefits of ESS may not be fully appreciated, especially concerning its value in increasing the energy system resilience, which is difficult to monetise.

A holistic approach to KPI determination and interpretation is necessary for optimizing energy systems beyond siloed sectoral or technology-specific perspectives. Flexible sector coupling, linking electricity, heating, cooling, and mobility particularly with energy storage as the flexibility enabler remains an area where unrecognised benefits could significantly enhance the economic feasibility of certain ESS, in particular thermal ESS.

The contextual dimension is equally critical: economic feasibility and perceived value vary substantially depending on the stakeholder and intended application. Aligning KPI frameworks with these differing viewpoints will improve decision-making, investment prioritization, and policy design. The example calculations presented in this report illustrate how selected KPIs operate in practice and reinforce the need for context-aware evaluation.

Key future work could focus on refining and standardizing KPI definitions for broader applicability across technologies and markets. Another interesting work would be integrating non-monetary and system-level benefits, such as resilience, emissions reduction, and societal value, into economic assessments. Additionally, developing models to quantify revenue stacking under evolving market structures will prove beneficial.

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6 Benefit-Revenue-Cost Approach

6.1 Description of the Approach

This approach shall give a very first idea of the economic performance of a specific storage technology within an actual use case. Potential benefits and revenue streams for a given time period as well as system cost have to be estimated to get a general “feeling” for the possible economic evaluation of the energy storage.

Energy storage systems can provide a wide range of benefits to a number of stakeholders in certain applications or use cases. Many times a single storage installation can offer multiple benefits for different target groups. As an example, large battery storages offer flexibilities to electricity grid operators, allow a manageable energy supply from PV plants or arbitrage possibilities to the storage operator at the same time.

However the value of the different benefits can differ a lot. Some of the benefits of energy storage installations are not remunerated, e.g. black start capability. On the other hand, some benefits in certain use cases can create high values and attractive revenue streams.

Promising business cases can be created when it is beneficiary to invest in specific storage solutions due to a clearly defined revenue stream over a certain period. The investing party shall have the financial benefits from the storage operation. This simple statement becomes complex as soon as “multi-use” operations come into play. In many cases it is not simple to identify the party which pays and receives the revenues. Such situations lead to uncertainties and prevent successful implementation of energy storage systems.

The approach presented here is based on an approach by IRENA. Figure 6-1 shows three columns, benefits, cost and revenues of an energy storage system. In this case it is a battery operated within the electricity grid. Five different benefits were identified, from ancillary services to peak plant savings. This was compared to the cost, consisting of four expense categories. The final column on the left showed the expected revenues, discharge revenues, ancillary services payment, and capacity payment.

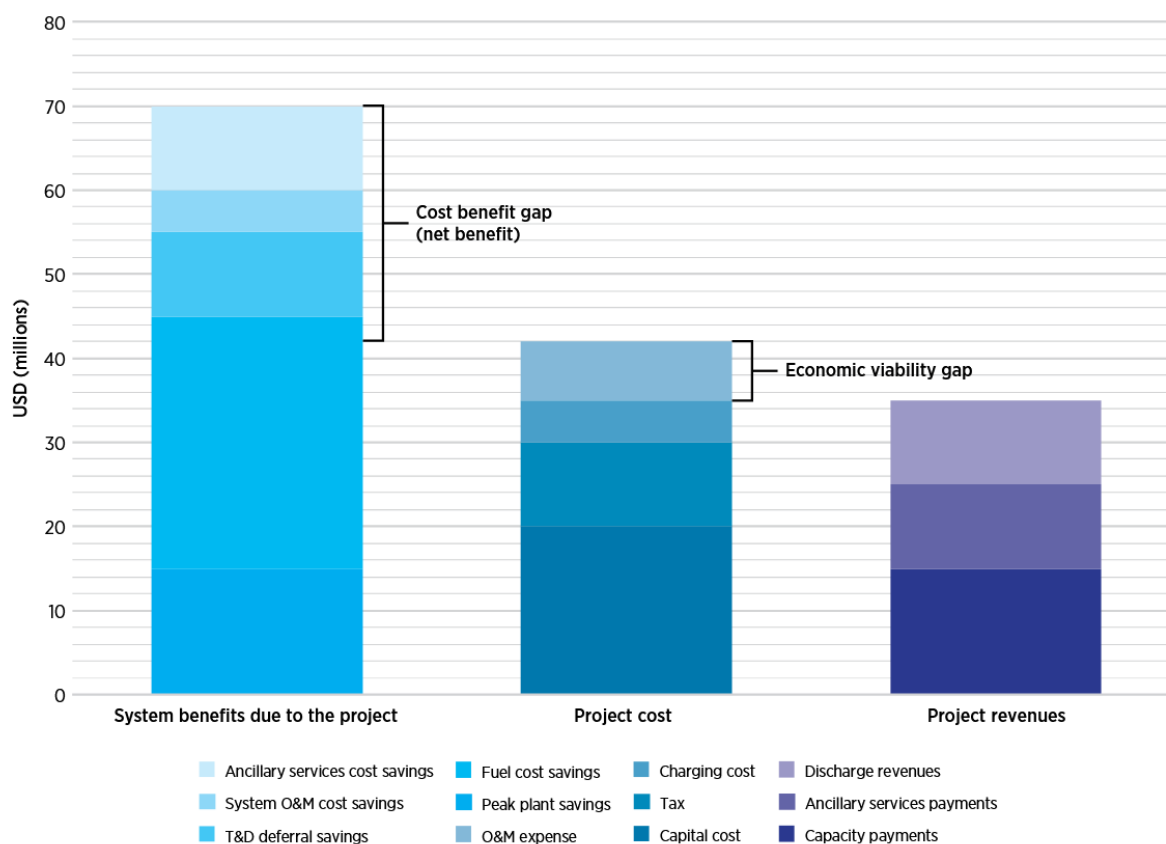


Figure 6-1: Benefit-Cost-Revenue approach from IRENA [69].

The approach developed within Task 41 shows a slightly different picture (Figure 6-2). Here the columns for benefits, revenues, and cost changed order. *Benefits* represent all the positive implications which the operation of the specific energy storage solution can provide. Some of them might be beneficial in a very general sense without creating any revenue. That means the benefit column is always higher (or equal) to the revenue column. The revenues are given by the possibilities to realise any remuneration of the benefits from the storage installation. The third column, the cost column, represents the actual energy storage system cost. If the cost column is smaller than the revenue column (over a given time) the discussed energy storage application seems to create a promising business case (see Figure 6-2).

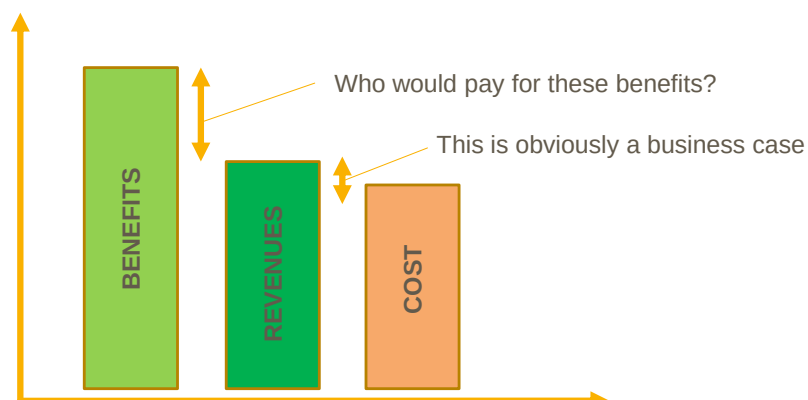


Figure 6-2: Benefit-Revenue-Cost approach developed in Task 41 – illustration for a promising business case.

If the revenue column is smaller, the economic viability of the storage solution is questionable (see Figure 6-3). In such cases, some of the benefits might not be able to create revenue streams. For example, a stationary battery within the electricity grid might provide black start capabilities, which is remunerated today. But this might change in the future, and the revenues might increase and finally a business case might be created.

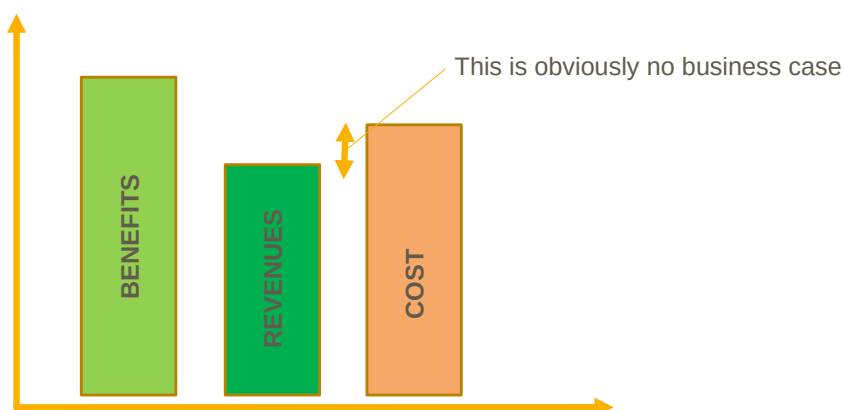


Figure 6-3: Benefit-Revenue-Cost approach developed in Task 41 – illustration for a questionable business case.

This approach can identify promising storage configurations in a very simple way, and it is able to show which benefits must become revenue-relevant in the future to develop an overall sustainable energy system. The transformation from *benefits* to *revenues* can very much depend on the regulatory framework. That is why this approach can be helpful in any discussion with decision makers about the role of energy storage within the integrated energy system.

6.2 Examples

Two examples of energy storage systems within certain applications explain the developed approach. One is a cold storage within a fridge-freezer-combination (a comparably small energy storage); the second is a mobile heat storage for the utilization of industrial waste heat.

6.2.1 Power-to-Cold – Energy Storage within a Fridge

The idea of the first use case is a cold storage within a household appliance, in this case a fridge-freezer-combination. If they are connected intelligently (e.g. by smart meter), a large number of these units can resemble a huge **dispatchable load** within the electricity grid by transforming electricity to cold.

Assuming 20 million fridges in Germany, which is less than 50% of households, are equipped with such a latent cold storage. The PCM storage can provide cold supply for 7-8 hours. It needs about 2-3 hours to charge the storage. The storage capacity is 0.175 kWh. The cost for this cold storage device integrated in the fridge is about 5 €.

Under these assumptions, an **electric power** of about **1.15 GW** and a **storage capacity** of **3.5 GWh** can be realised within the electricity grid.

In case there is too much electricity in the grid, e.g. from renewable energy sources, the agglomerated storage capacity can be used to charge the cold storages with the electric power indicated. If there is a lack of electricity, all equipped fridges can be taken from the grid and provide cold from the PCM devices. Figure 6-4 shows the PCM storage component on the fridge.



Figure 6-4: Latent cold storage within a fridge/freezer combination.

For this storage configuration, a list of **benefits** was collected:

1. Dispatchable load for grid balancing
2. Uninterruptable cold supply
3. Peak load reduction
4. Curtailment reduction / Higher RE utilization
5. Arbitrage

The first benefit is valuable for grid operators. It provides controllability and flexibility for the grid and can be quantified in energy (kWh) and power (kW). The fourth benefit allows a better utilization of surplus electricity from wind/PV. This might be interesting for renewable energy producers or utilities. This benefit can be quantified in energy (kWh) and power (kW).

The other benefits - uninterruptable cold supply, peak load reduction and arbitrage – can be valuable for the consumer, the owner of the fridge. The security of cold supply might be extremely valuable, when you face a weak electricity grid, e.g. in case of keeping cooled medicine in hospitals located in a developing country. Peak load reduction might result in reduced cost of peak power supply (kW). Finally the consumer could buy cheap electricity at times of high renewable input to the grid and reduce its consumption, when electricity is expensive (kWh).

In this example, three different stake holder groups are benefitting from the storage use case. Each benefit is theoretical able to provide **revenues**. In the following points these revenue streams will be quantified.

- The dispatchable load for grid balancing could be utilised as primary control power. For this power reserve about 10,000 €/MW will be paid. The fridge with its nominal power demand of 57 W this would result in 0.57 €, which is quite a small amount of money.
- To quantify the revenues of the uninterruptable cold supply, the cost for an alternative to the PCM storage, e.g. cost for a fossil fuel based generator, were calculated. Assumed the electricity from such a small scale generator is about 0.50 €/kWh and the energy consumption of a quite efficient fridge is about 100 kWh/year and 10% of the time the fridge has to be run on the cold storage, this would result in a revenue of 5 € per year.
- Peak load reduction is no option for private households, at least in Germany, and was not considered in this calculation.
- For the quantification of revenues for higher utilization of renewable electricity sources the number of charging/discharging cycles for renewable surplus energy has to be assumed. With 50 storage cycles per year and an electricity price of 0.05 €/kWh only 0.44 € ($50 \cdot 0.175 \text{ kWh} \cdot 0.05 \text{ €/kWh} = 0.44 \text{ €}$) could be remunerated.
- Arbitrage, however, leads to much higher revenues. Assuming a price difference of a factor of 2 (0.1 € to 0.2 €), 0.1 €/kWh could be expected. If charging at low price and discharging at higher price is possible for 50% of the fridges' electricity demand per year (50 kWh per year) revenue of 5.00 € per year could be realised.

In Figure 6-5 the results are visualised for one year operation. It becomes clear that almost all of the benefits are generating revenues. Some of them are quite small and will probably not be utilised. The two most relevant revenue streams - uninterruptable cold supply and arbitrage – lead to a payback time shorter than one year and are both related to the same stake holder group, the consumer.

Visualizing Benefits, Revenues and Cost

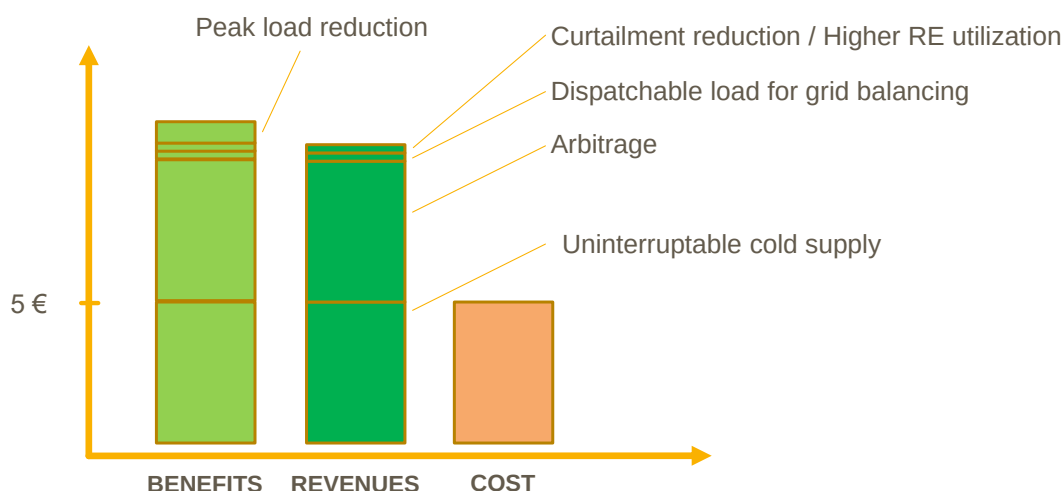


Figure 6-5: Benefit-Revenue-Cost approach developed in Task 41 applied to a latent cold storage within a fridge/freezer combination.

This, slightly exotic, energy storage application seems to be economic feasible.

6.2.2 Thermochemical Mobile Sorption Storage

The second use case describes a mobile heat storage system based on water adsorption on zeolites. These thermochemical storages can provide hot and dry air, which is very suitable for industrial drying processes. Furthermore, open sorption storage solutions can provide high storage capacity and are able to deliver heat at higher temperatures during discharging compared to the available charging temperature.

In this use case the mobile sorption storage unit is placed on a truck and collects waste heat from a waste incineration plant. It transports the heat to a drying process in 8 km distance. The 14 t of zeolite are able to store about 3.5 MWh waste heat. The maximum charging and discharging power are in the range of 0.75 to 1 MW. Therefore, one cycle takes about 9-10 hours (including transportation).

For the specific use case 876 storage cycles were assumed over one year, which is actually the maximum possible number of cycles. Due to actual charging temperature of 135 °C a realistic energy capacity of 2.8 MWh was measured. One mobile storage unit leads to CAPEX of about 143,000 €. This cost estimation is quite conservative. Further cost reduction is most likely as more of these units will be built in the future.

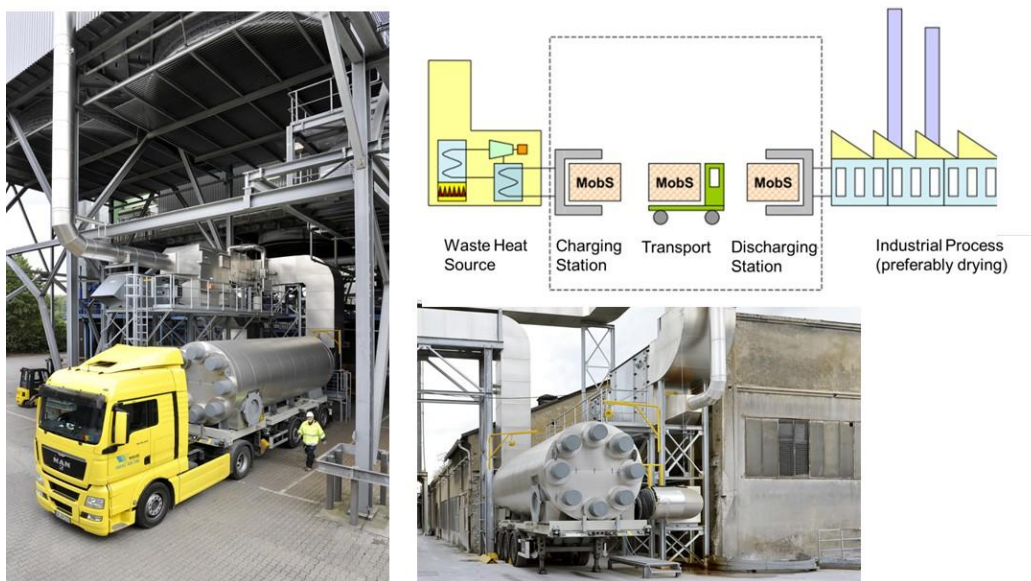


Figure 6-6: Mobile sorption storage at the charging station (Waste-to-energy plant), schematic view of the application and the discharging station at the industrial drying process (below right).

For this storage configuration a list of **benefits** was collected:

1. Waste Heat Utilisation
2. CO₂ Emission Reduction
3. Avoided District heating system cost

The first benefit allows the operators of the waste-to-energy plant to sell the waste heat outside the plant. In the actual case it was sold to industrial drying process. The cost for the collected and charged waste heat to the thermal energy storage is 65 €/MWh (calculated based on the actual utilised amount of heat per year). It is basically caused by the OpEx for the charging/discharging stations.

The CO₂ emission reduction can create revenues for the industrial drying process by replacing fossil fuel combustion.

Each benefit is theoretically able to provide **revenues**. In the following points these revenue streams will be quantified:

- The waste heat utilization creates revenues by supplying heat to the drying process. Today heat can be discharged and supplied according to the average price for district heat, which is around 120 €/MWh. Considering the actual cost for the waste heat at 65 €/MWh, the effective revenue would result in 55 €/MWh delivered at the consumer side. Furthermore assuming a total heat supply of 2,453 MWh/year, this would result in **134,900 €/year**.
- The achieved CO₂ emission reduction is assumed to be remunerated with about 55 €/t CO₂. The CO₂ emissions from gas fired heat production are 316 kg/MWh. If the gas fired heat supply is fully replaced by mobile waste heat (2,453 MWh/year), this would lead to about 775 t CO₂ emission reduction. Which would result in about **42,500 €/year**. This revenue stream flows to the operators of the drying process.

- Mobile heat storages are one possibility to transport heat over longer distances. This solution is competing with district heating pipes. In specific use cases the cost for heat pipelines can be very high. This benefit of the mobile sorption system, however, is difficult to quantify and depends strongly on the local conditions.

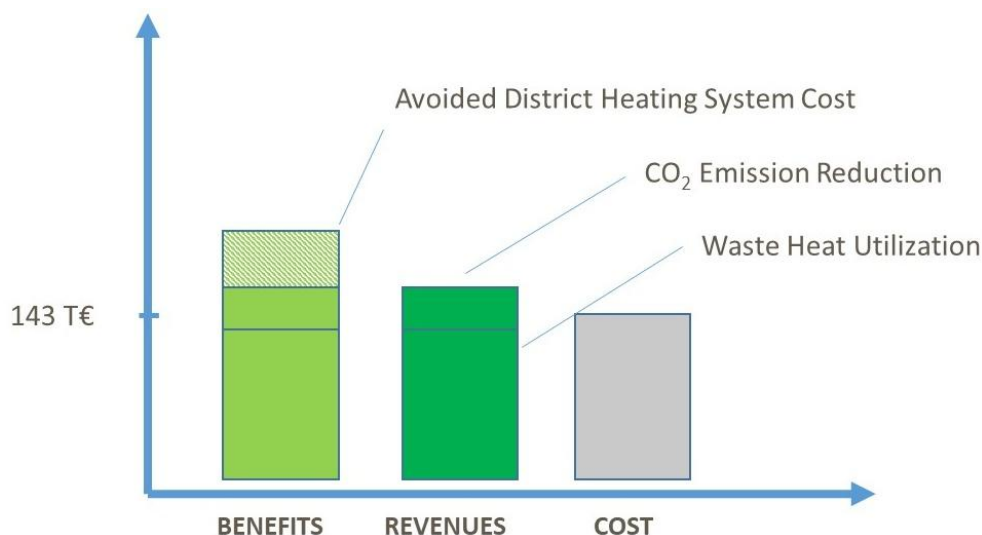


Figure 6-7: Benefit-Revenue-Cost approach developed in Task 41 applied to a mobile sorption storage for waste heat recovery. CAPEX of one mobile sorption storage unit is approx. 143,000 €.

In Figure 6-7 the results are visualised for one year operation. It becomes clear that the waste heat utilization alone might not be able to provide payback time below one year. The possible revenue from avoided CO₂ emissions is necessary to reach such low theoretical payback times. Buying the waste heat from a waste-to-energy plant can be even more attractive since heat from waste incineration plants is defined as “green” (carbon-neutral) by EU regulations.

6.3 References

- [69] Taibi, E., Nikolakakis, T., Fernandez, C., Vaid, A., Yu, A., Walimbe, V., ... & Johnson, R. (2020). Electricity storage valuation framework 2020. Available online: www.irena.org

7 Maximum Acceptable Energy Storage Cost Approach

In this chapter, the so-called maximum acceptable storage capacity cost approach will be presented ([70], [71]). Following the introduction of the approach (section 7.1) and its application to collected cases (sections 7.2 and 7.3), the extension of this approach for a more realistic evaluation of the economic viability of energy storage systems will be reported (section 7.4).

7.1 Description of the approach

This section introduces two evaluation methods including the *top-down approach* (subsection 7.1.1) and *bottom-up approach* (subsection 7.1.2) and combines the two methods to evaluate the *maximum acceptable storage capacity costs* of different energy storage systems (subsection 7.1.3).

7.1.1 Top-down approach

The top-down approach assumes that the maximum acceptable costs of energy supplied by a storage system should not exceed the cost of energy from the market. Following this assumption, as shown in Eq. (7-1) and Eq. (7-2), the maximum acceptable storage capacity costs (referred to as SCC_{acc}) are calculated from the interest rate assigned to the capital costs, the intended payback period of the user class (e.g., industry or building), the costs of energy from the market, and the annual number of storage cycles [71]. Note that the substituted reference energy cost is strongly related to the market and should be changed for projects located different countries. To simplify the evaluation, this analysis neglects operating costs and changes in the cost of energy production over time.

$$SCC_{acc} = \frac{REC \cdot N_{cycle}}{ANF} \quad (7-1)$$

$$ANF = \frac{(1+i)^n \cdot i}{(1+i)^n - 1} \quad (7-2)$$

where REC is the reference energy cost (i.e., the costs of energy from the market), $\text{€} \cdot \text{kWh}_{cap}^{-1}$; N_{cycle} is the number of storage cycles per year; ANF represents the annuity factor; i is the interest rate; n is the payback period.

Interest rate i and payback period n depend on the user class. This report involves two user classes: building sector and industry sector. In the industry sector, high interest rates of 10% and short payback periods of 3-5 years are usual. For building applications, moderate interest rates of 5% and longer payback periods of 15-20 years are acceptable.

Figure 7-1 shows the relationship between the ANF and the payback period under the building and industry sectors. The value of ANF decreased as the payback period increased. When the payback period was within 5 years, the ANF value decreased significantly. While when the payback period

exceeded 5 years, the *ANF* value decreased slowly and tended to be stable. The blue dashed curve represents industry sector, while the solid red curve applies to the building sector. The framed regions show that the acceptable boundary of *ANF* of the building sector ranged from 0.08 to 0.1 under the payback periods of 15-20 years, and that of the industry sector ranged from 0.26 to 0.41 under the payback periods of 3-5 years.

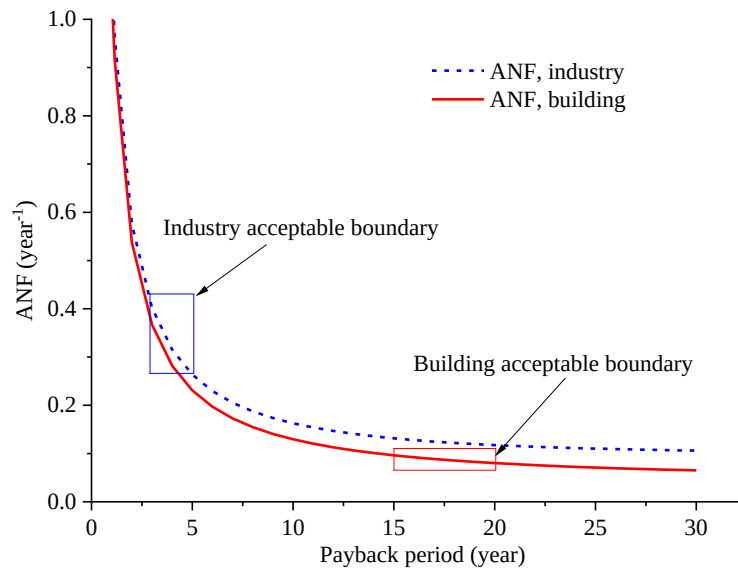


Figure 7-1: *ANF* as a function of payback period for two user classes; framed regions indicate acceptable the *ANF*.

7.1.2 Bottom-up approach

The bottom-up approach focuses on the realised storage capacity costs (referred to as SCC_{real}) of existing storage systems. As shown in Eq. (7-3), the SCC_{real} is simply the investment costs (INC) divided by the installed storage capacity (SC). INC sums up heat storage material costs, storage container or reactor costs, and cost of charging and discharging device. The values of the INC and SC for a particular storage system are collected from the questionnaire.

$$SCC_{\text{real}} = \frac{INC}{SC} \quad (7-3)$$

where INC is the investment cost, €; SC is the storage capacity, kWh_{cap} .

However, some respondents did not directly provide the INC of the energy storage project, but provided capital expenditures ($CAPEX$), maximum discharging power (MDP) and full discharge duration (FDD). Therefore, this report also uses the following formula to estimate the SCC_{real} of the project:

$$SCC_{\text{real}} = \frac{CAPEX \cdot MDP}{SC} = \frac{CAPEX}{FDD} \quad (7-4)$$

Where MDP is the maximum discharging power, kW; FDD is the full discharge duration at the maximum discharging power, h.

Take an example to compare the calculated results by Eq. (7-3) and Eq. (7-4). The selected project (P7) is the short-term PTES system in Høje Taastrup, Denmark. According to [72], the value of the INC and SC of the PTES are approximately € 12 million and 3,300 MWh, respectively, leading to a calculated SCC_{real} of 3.64 €/kWh via Eq. (7-3). Based on the data collected from the questionnaire, the $CAPEX$ is 385 €/kW, with a MDP of 30 MW and a FDD of 110 h, resulting in SCC_{real} of 3.50 €/kWh using Eq. (7-4). The close agreement between these two results suggests that Eq. (7-4), which relies on commonly reported parameters such as $CAPEX$, MDP , and FDD , can serve as a reliable and practical approach for estimating the realised storage capacity cost of energy storage systems.

7.1.3 Combined top-down and bottom-up approach

This subsection selected four thermal storage projects (P1, P7, P8, and P9) that were all used for building heating and evaluated their economic feasibility by combining the top-down/bottom-up approaches. The selected four projects are all located in Denmark and thus the reference energy is selected as the natural gas. The economic boundary conditions, including the cost of substituted natural gas and the corresponding ANF , are shown in Table 7-1. Note that the cost of natural gas in Denmark has increased since 2022, thus, the average price for the intended payback period was considered. From Table 7-1, the average REC ranged from 0.08 to 0.12 €·kWh_{cap}⁻¹ for building sector and that ranged from 0.04 to 0.06 €·kWh_{cap}⁻¹ for industry sector. The changes of ANF were obtained in subsection 7.1.1.

Table 7-1. The economic boundary conditions when calculating the maximum acceptable storage capacity costs of energy storage systems for building heating.

User class	Average REC (€·kWh _{cap} ⁻¹)		ANF (year ⁻¹)	
	Min.	Max.	Min.	Max.
Building	0.08	0.12	0.08	0.1
Industry	0.04	0.06	0.26	0.41

Figure 7-2 shows the maximum acceptable storage capacity cost changes with the storage cycles per year (N_{cycle}) for two user classes. According to Eq. (7-1), the high case of the SCC_{acc} considers the maximum REC and the minimum ANF , while the low case of the SCC_{acc} considers the minimum REC and the maximum ANF . Solid lines indicate the high case of each user class and dashed lines represent the low case, respectively. When the realised storage capacity cost of an energy storage system is less than the accordingly high case of the SCC_{acc} , it can be considered economically viable. From Figure 7-2, the SCC_{acc} increases with the number of annual storage cycles, indicating that the short-term storage systems are more likely to achieve economic viability than long-term energy storage systems. Across

the full range of annual storage cycles, the building-sector curves (red) lie well above the industrial curves (blue), therefore, the acceptable range of the storage capacity cost in the building sector is larger than that in the industry sector. In addition, the change curves of the building sector have higher growth rate, meaning that the energy storages in building sector are more sensitive to the market (e.g., the interest rate). Note that, when the seasonal stores operate at $N_{\text{cycle}} < 5 \text{ year}^{-1}$, the SCC_{acc} for all curves tends toward zero, in other words, very long-term storage systems must be built at extremely low specific costs—or subsidised—if they cycle only once or twice per year.

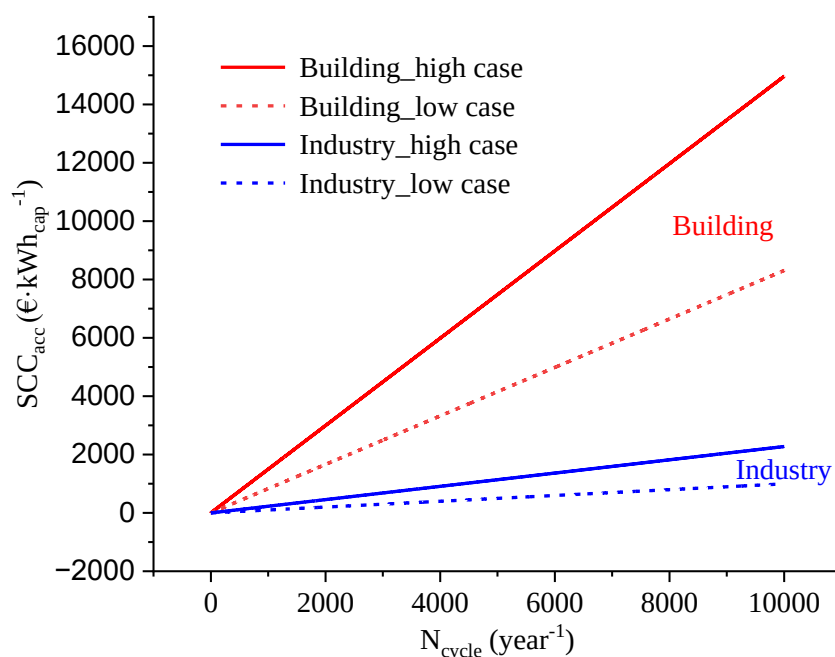


Figure 7-2: Maximum acceptable storage capacity costs (SCC_{acc}) changes with storage cycles per year (N_{cycle}).

Figure 7-3 presents the maximum acceptable storage capacity cost changes with the storage cycles per year (N_{cycle}) for two user classes under the double-logarithmic coordinate system. This representation enhances visibility and interpretability across the full spectrum of storage types—from ultra-low-cycle, long-term systems (e.g. seasonal thermal storage) to high-frequency, short-term systems (e.g. batteries). The linear appearance of all four curves in log–log space confirms that the relationship between the SCC_{acc} and N_{cycle} scales across many orders of magnitude. If the storage cycles per year increase tenfold, the maximum acceptable storage capacity cost also increase by a factor of ten. In addition, the vertical relation between the red and blue curves remains constant across the entire x axis. This suggests that the relative economic tolerance for investment costs between building sector and industry sector is preserved regardless of the number of storage cycles.

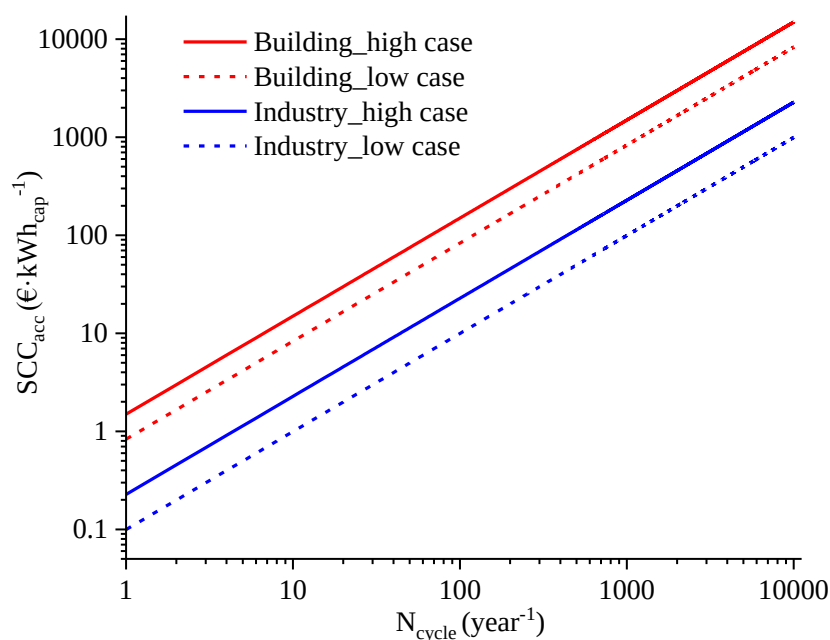


Figure 7-3: Maximum acceptable storage capacity costs (SCC_{acc}) changes with storage cycles per year (N_{cycle}) under the double-logarithmic coordinate system.

Figure 7-4 shows the maximum acceptable storage capacity cost (SCC_{acc}) derived with the top-down approach against the realised storage capacity cost (SCC_{real}) for four thermal-storage projects obtained with the bottom-up approach. P1, P8, and P9 are long-term thermal storage projects for district heating, and their annual storage cycles are 2-2.5, 1, and 0.6 respectively. P7 is a short-term thermal storage project for district heating, and its annual storage cycle ranges from 25 to 30. From Figure 7-4, the realised storage capacity cost of the three PTES systems (P1, P7, and P8) are all less than the lower limit of the maximum acceptable storage capacity cost, while the BTES system (P9) is slightly exceeds the low case acceptable cost but lower than the high case acceptable cost, which highlights the stricter cost constraints imposed on the borehole configuration, because the borehole and manifold expenditures dominate the total capital expenditure. In contrast, although the P7 is technically the same as P1 and P8, its annual storage cycles increase by an order of magnitude, and the maximum acceptable storage capacity cost also increases by an order of magnitude, therefore, its realised cost is still far below the economic allowable range.

In summary, the results confirm two findings: 1) the economic space for thermal energy storage depends strongly on the annual storage cycle, with short-term energy storage systems bearing much higher unit investments than seasonal energy storage systems; and 2) at a given annual storage cycle level, PTES systems have a clear cost advantage over borehole systems, making PTES systems currently the more favourable choice for large-scale, long-term thermal energy storage in Denmark [73]. Note that the uniform natural gas price assumption adopted in this section is intended to standardise the comparison results. For different projects, the maximum acceptable cost should be analyzed according

to the actual situation. Consequently, subsequent chapters will use project-specific energy price data obtained from the questionnaire survey to refine the assessment.

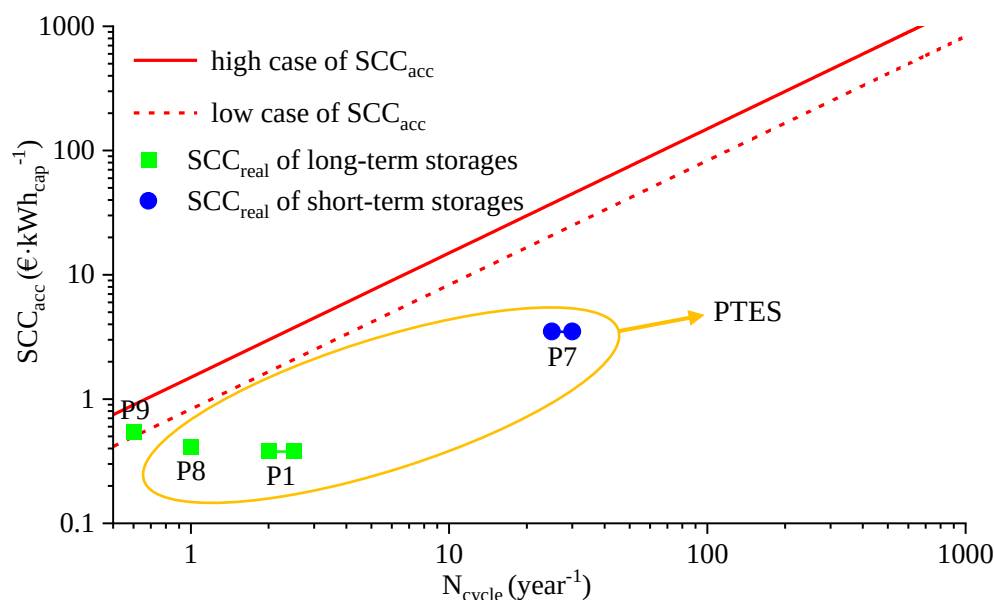


Figure 7-4: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}) for four thermal storages.

7.2 Collected energy storage cases

The activities, reported here, concentrate on determining the maximum acceptable energy-storage costs for different configurations. The concept of the maximum acceptable energy-storage cost sets an upper investment cost threshold beyond which a storage project no longer meets minimum financial criteria. Determining the maximum acceptable cost for each energy storage project is critical for: 1) guiding technology developers toward cost targets that unlock addressable markets; 2) informing policymakers about the cost gaps that may justify support mechanisms; and 3) helping investors screen opportunities and structure bankable business cases.

14 pilot cases were collected covering battery, pumped hydro storage, latent/sensible thermal storage, hydrogen storage, and compressed air energy storage from participants in six countries. For each case, techno-economic information—including capital expenditure, operating costs, revenue streams, and policy context—have been compiled using a common questionnaire developed by DTU and Task partners. This report applies the top-down / bottom-up methodology to quickly identify which energy storage projects are already competitive, which need incremental cost reduction and which require disruptive breakthroughs. The resulting cost ceilings provide a quantitative reference for stakeholders seeking to accelerate economically viable storage deployment in support of the clean-energy transition.

For the convenience of the economic assessment, this section provides a brief summary of the basic information (subsections 7.2.1 and 7.2.2) and techno-economic information (subsection 7.2.3) of the collected various energy storage types from questionnaires.

7.2.1 Energy storage types

Table 7-2 shows 14 pilot projects encompassing ten distinct energy storage technologies. Thermal concepts dominate the samples, with nine installations ranging from large pit and borehole seasonal storages to latent and sensible heat units. Electrical storage is represented by two compressed air energy storage (CAES) plants, a pumped hydro facility and an experimental sea-salt battery. Chemical storage appears through one hydrogen project. Geographically the cases span six European countries. This deliberately diverse portfolio ensures that subsequent analyses of maximum acceptable storage costs capture the contrasting cost drivers and cycling profiles of short-term electrical systems and long-term thermal stores within district heating networks.

Table 7-2. The energy storage types and their locations and quantities.

Energy storage types	Country and project number
Pit thermal energy storage (PTES)	Denmark: 3
Latent thermal energy storage (LHTES)	Austria: 1, Norway: 1
Compressed air energy storage (CAES)	Germany: 1,
Borehole thermal energy storage (BTES)	Denmark: 1
Molten Salt	Denmark: 1
Sea salt battery	Netherlands: 1
Pumped hydro storage (PHS)	Austria: 1
H ₂ energy storage	Austria: 1, United Kingdom: 1
Sensible thermal energy storage (STES) in the packed bed	Denmark: 1
STES in the District heating (DH) networks	Hungary: 1

7.2.2 Basic information

Table 7-3 provides an overview of 14 energy storage cases, summarising their location, application scenario, storage type, lifetime, annual storage cycles, and project status or special notes. These entries illustrate the diversity in both technical characteristics and stages of development across storage technologies.

The application scenarios of collected cases are dominated by building heating supply, accounting for the majority of the thermal storage systems such as PTES, BTES, STES, LHTES, and molten salt. A smaller number of cases serve building power supply, industrial cooling, or gas supply, reflecting broader use-cases for electrical or chemical storage types like CAES, PHS, hydrogen storage, and batteries.

For the LHTES (P3, P11) and STES (P10, P12) technologies, additional relevant details are: Project 3 used bio-based wax phase change material (PCM) with a melting point of 37 °C, the system integrated

with a low-temperature heating setup powered by propane and an air-to-water heat pump; project 10 located at Hørsholm, Denmark, simultaneously supplies the power and heating to buildings because it applies the technology of combined heat and power (CHP); project 11 used the ice storage technology for milk cooling demonstrates an innovative approach to utilizing surplus electricity through power-to-cold solutions; and project 12 used the surplus electricity to raising temperatures in district heating networks.

Storage lifetimes of collected cases range from 20 years for lab-scale or early-stage systems (e.g. LHTES and STES) up to 80 years for mature technologies like PHS. Some entries note flexible or indefinite lifetimes (“available forever”), particularly for systems like hydrogen CAES that involve reservoir or continuous upgrading.

The annual storage cycle is defined as the number of times in one calendar year that the store is taken through a full charge–discharge sequence, i.e. from its minimum usable temperature (or energy content) up to its design maximum and back again. From Table 7-3, the annual storage cycle varies significantly, highlighting the wide range of storage roles: 1) long-duration, seasonal thermal systems such as BTES and PTES typically operate at very low cycle rates (e.g. 0.6 to 2.5 cycles/year), designed for shifting energy across seasons; 2) medium-duration systems (e.g. molten salt, LHTES) show moderate cycles (25–365 per year), aligning with daily to weekly flexibility needs; 3) short-duration systems like sea salt batteries can cycle up to more than 4,000 times per year, indicating multiple charge–discharge operations per day, suitable for grid balancing or fast-response applications.

In terms of development status, the projects range from fully operational (e.g. PTES in Dronninglund or molten salt in Northern Jutland) to early-stage concepts or trial systems (e.g. hydrogen CAES in Austria, STES in Hungary, PHS in Ebensee). A few projects are still under construction or have not yet been built (e.g. CAES in Germany, hydrogen system in the UK), providing insight into technologies on the verge of deployment.

Table 7-3. The basic information of the collected energy storage types.

Series	Location	Application scenario	Storage type	Lifetime	Annual storage cycle	Note
P1	Dronninglund, Denmark	Building heating supply	PTES	25	2-2.5	
P2	Northern Jutland, Denmark	Building heating supply	Molten salt	25	278	
P3	Trondheim, Norway	Building heating supply	LHTES	25	240	At laboratory
P4	Ahaus, NRW, Germany	Industry and building Power supply	CAES	>30	365	Not build yet

Series	Location	Application scenario	Storage type	Lifetime	Annual storage cycle	Note
P5	Delft, Netherlands	Building Power supply	sea salt battery	>30	4,380	
P6	Chester, UK	Building Power supply	Hydrogen CAES	40-60	≈720	Not build yet
P7	Høje Taastrup, Denmark	Building heating supply	PTES	>20	25-30	
P8	Marstal, Denmark	Building heating supply	PTES	25	1	
P9	Brædstrup, Denmark	Building heating supply	BTES	≥25	0.6	
P10	Hørsholm, Denmark	Building power and heating supply	STES	≥25	50-100	Being construction
P11	Gallneukirchen, Austria	Industry cooling	LHTES (Power to cold)	20	100-365	
P12	Hungary	Building heating supply	STES (Power to heat)	20	*	
P13	Ebensee, Austria	Building power supply	PHS	80	230	Concept stage
P14	Austria	Gas supply	Hydrogen CAES	Available forever	≈1	Trial state

Note: * means charging cycle whenever excess power is made available.

7.2.3 Techno-economic information

Table 7-4 shows the key techno-economic parameters reported for the 14 storage cases. Usable capacities run from a small-scale latent-heat cooling storage unit of roughly 100 kWh (P11) to an envisaged underground hydrogen cavern of about 70 GWh (P14); most thermal stores, such as water pit (P1, P7, P8) and borehole (P9) systems, fall in the mid-gigawatt-hour range, while electrical (P3, P10) and chemical (P2) demonstrators occupy the tens-to-hundreds of megawatt-hours bracket.

Full discharge duration is defined as the time that the energy storage system can discharge at the maximum discharge power. The full-discharge durations differentiate daily balancing from seasonal operation: small-scale hydrogen CAES (P6), small-scale latent-heat cooling storage (P11), and pumped hydro plants (P13) empty within 5–12 h, whereas large pit or borehole stores can release heat for weeks—416 h for P1 and up to 3 600 h for P9—confirming their role as long-duration assets.

Capital expenditures (CAPEX) of these collected cases are equally scattered. Mature, high-volume technologies show the lowest reported specific costs: the PTES case (P1) is just $100 \text{ €} \cdot \text{kW}^{-1}$ and the conceptual hydrogen cavern (P14) only $44.36 \text{ €} \cdot \text{kW}^{-1}$. At the opposite extreme, the small-scale BTES pilot coupled with storage tank (P9) reaches $5,731 \text{ €} \cdot \text{kW}^{-1}$ and the pumped-hydro concept in Ebensee, Austria (P13) stands at $2,500 \text{ €} \cdot \text{kW}^{-1}$, illustrating how engineering complexity, site conditions and scale strongly influence the CAPEX. Operating expenditures (OPEX) are sparse but vary by two orders of magnitude, from a negligible $0.013 \text{ €} \cdot \text{kW}^{-1}$ for PTES to $5.4 \text{ €} \cdot \text{kW}^{-1}$ for BTES, reflecting differences in auxiliary power, monitoring requirements and maintenance regimes.

Payback periods of these collected cases range from 2–4 years (P5) to 20 years (P1 and P8) for thermal systems integrated into district heating. Mid-range payback times are observed for P7 (11.6 years) and P9 (13.4 years), suggesting economically feasible returns in contexts with technology improvement or policy support. P10, a hybrid CHP system, indicates a relatively short, expected payback of 3–8 years, reflecting its dual revenue potential. The payback times of P11 and P12 are only 7 years and 3 years, representing the utilizing surplus electricity via power-to-X for short-term storages yields significant investment value.

Although the collected questionnaire provided a valuable first snapshot of each storage project, it did not yield a complete techno-economic data set for every case. This limitation is partly intrinsic to the sector: large-scale storage schemes typically unfold over many years, and the level of detail that project teams can share depends heavily on where they sit along that timeline. Projects in the feasibility or concept phase seldom have firm cost figures, while those in construction may be negotiating contracts that prevent disclosure. In addition, commercial sensitivities (e.g. competitive procurement, or investor confidentiality agreements) often restrict access to granular CAPEX, OPEX and revenue assumptions. Finally, disparate accounting conventions across countries and sectors (power vs. heat vs. hydrogen) complicate the direct comparison of figures supplied.

Consequently, three cases—P2, P3, and P4—do not provide the minimum information required for a robust maximum acceptable cost calculation. Specifically: P2 is a fully commercial project operated for corporate profit, the owner disclosed only headline capacity data and withheld detailed costs; P3 is a laboratory-scale latent-heat unit still in experimental operation, so real-world investment and operating figures are not yet available; P4 remains in the concept-development stage, and their design envelopes and cost estimates are preliminary and subject to major revision. Note that, the respondent also does not provide the minimum information of the P10 for economic evaluation, but we can obtain the realised capacity cost from the website of the host company, thus, a brief analysis can be done for this project.

Table 7-4. The techno-economic information of the collected energy storage types.

Series	Storage Capacity (kWh)	Capital expenditures, (€/kW)	Operational expenditures, (€/kW)	Full discharge duration (h)	Payback period
P1	5,000,000-5,500,000	100	0.013	416-458	20
P2	18,000	/	/	4.5	/
P3	>200	/	/	24	/
P4	2,560,000	/	/	8	10
P5	2	190-390	/	1	3
P6	200,000	1,320	0.1-0.24	5	/
P7	3,300,000	385	0.88	110	11.6
P8	6,000,000	305	2.52	600	20
P9	480,000	5,731	5.4	3,600	13.4
P10	300,000	/	/	/	3-8
P11	100	3,950	/	9	7
P12	12,000	94	/	2.4	3
P13	1,734,000	2,420	0.13	9	/
P14	70,000,000,000	32.5	/	2,300	/

Note: symbol '/' means no information provided from the questionnaire.

7.3 Economic evaluation of collected cases

This section evaluates the maximum acceptable storage capacity cost, derived using the top-down approach, against the realised storage capacity cost for each project based on the collected data. Four projects (P2, P3, and P4) do not provide the minimum information required for a maximum acceptable cost calculation, thus this section includes ten projects in total to analysis. The results for four long-term energy storage systems (P1, P8, P9, and P14) are presented in subsection 7.3.1, while those for seven short-term storage systems (P5, P6, P7, P10, P11, P12 and P13) are provided in subsection 7.3.2.

7.3.1 Long-term energy storage

7.3.1.1 Pit thermal energy storage in Dronninglund, Denmark

The PTES in Dronninglund, Denmark (P1) is currently in operation. Figure 7-5 presents an aerial view of the PTES system (P1) and the adjacent solar collector field. The 60,000 m³ storage facility was initiated in March 2013 and commenced operation in May 2014. As a representative example of state-of-the-art large-scale thermal storage, the system demonstrates a thermal efficiency exceeding 90% and achieves hot water storage temperatures of up to 95 °C. The PTES is used for both seasonal and

short-term storage of solar thermal energy produced by a 37,573 m² flat-plate collector array. The stored heat is either supplied directly to the district heating network or used during winter periods as an alternative source for a heat pump [74].



Figure 7-5: Aerial view of the PTES and solar collector field in Dronninglund, Denmark [75].

Table 7-5 summarises the economic and technical parameters of the PTES system in Dronninglund. An interest rate of 5% and a payback period of 20 years yield an annuity factor of 0.08, calculated using Eq. (7-2). The number of full storage cycles per year ranges from 2 to 2.5. The system's reference energy source is a bio-oil boiler, with a fuel cost of 0.07 €/kWh. According to data provided by PlanEnergi, the INC of the PTES is € 2,671,100, and the corresponding SC is 6,960,000 kWh. Based on these inputs, both the maximum acceptable storage capacity cost and the realised storage capacity cost for the Dronninglund system can be determined.

Table 7-5. The economic and technical parameters of the PTES system in Dronninglund, Denmark.

Interest rate	Payback period	ANF	N_{cycle}	REC (Bio-oil boiler, €/kWh)	INC (€)	SC (kWh)
5%	20	0.08	2-2.5	0.07	2,671,100	6,960,000

Figure 7-6 compares the maximum acceptable storage capacity cost (red line) with the realised storage capacity cost (blue triangles) for the PTES system in Dronninglund, Denmark. The two blue triangles represent the actual storage costs for the Dronninglund PTES under two operating scenarios: 2 and 2.5 full cycles per year, both with a corresponding SCC_{real} of 0.38 €/kWh. These points lie well below the SCC_{acc} threshold indicated by the red line, indicating that the system's investment cost is well within the economically acceptable range. This result demonstrates that the Dronninglund PTES offers strong economic performance under the real conditions. Even with a low annual storage cycle typical of seasonal heat storage, its specific cost remains significantly lower than the maximum acceptable value.

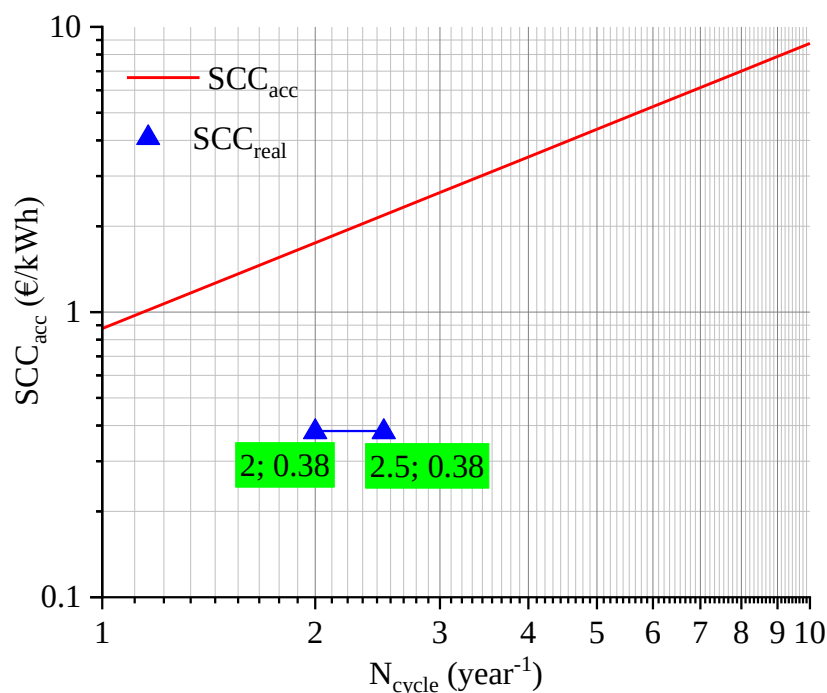


Figure 7-6: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}) for the PTES in Dronninglund, Denmark.

7.3.1.2 Pit thermal energy storage in Marstal, Denmark

Figure 7-7 shows aerial view of the PTES and solar collector field in Marstal, Denmark. The PTES (P8) is currently in operation. This water PTES system was constructed in 2012, with a capacity of approximately 6,000 MWh. The heat storage system was integrated with the local district heating system, which supplies heat to approximately 1,600 consumers. The pit was excavated in the shape of an inverse truncated pyramid with a volume of 75,000 m³. This PTES system is used for seasonal storage of heat generated by a solar collector field consisting of 15,000 m² of flat-plate collectors [76].



Figure 7-7: Aerial view of the PTES and solar collector field in Marstal, Denmark [77].

Table 7-6 presents the economic and technical parameters of the PTES system in Marstal. An interest rate of 5% and a payback period of 20 years result in an annuity factor of 0.08, calculated using Eq. (7-2). The system completes one full storage cycle per year. According to the collected data, two reference energy sources are considered: a bio-oil boiler and a wood chip boiler, with corresponding energy costs of 0.07 €/kWh and 0.03 €/kWh, respectively. Based on data from PlanEnergi, the total *INC* of the PTES is € 2,671,100, and the storage capacity (*SC*) is 6,960,000 kWh.

Table 7-6. The economic and technical parameters of the PTES system in Marstal, Denmark.

Interest rate	Payback period	<i>ANF</i>	N_{cycle}	<i>REC 1</i> (Bio-oil boiler, €/kWh)	<i>REC 2</i> (Wood chip boiler, €/kWh)	<i>INC</i> (€)	<i>SC</i> (kWh)
5%	20	0.08	1	0.07	0.03	2,281,900	5,570,000

Figure 7-8 compares the realised storage capacity cost (SCC_{real}) of the Marstal PTES with the maximum acceptable storage capacity cost (SCC_{acc}) derived under two alternative reference energy cost scenarios: *REC 1* (bio-oil boiler at 0.07 €/kWh) and *REC 2* (wood chip boiler at 0.03 €/kWh). For the Marstal PTES, which operates on a seasonal cycle with N_{cycle} equal to one, the realised storage cost (purple square) is 0.51 €/kWh, based on an investment cost of € 2,281,900 and a storage capacity of 5.57 GWh.

Under the *REC 1* scenario (bio-oil boiler), the SCC_{acc} value at one cycle per year is about 0.9 €/kWh, clearly above the SCC_{real} , indicating that the investment is economically feasible under these conditions. In contrast, under the *REC 2* scenario (wood chip boiler), the lower reference energy cost significantly reduces the SCC_{acc} to approximately 0.3 €/kWh. In this scenario, the realised cost (0.51 €/kWh) exceeds the maximum acceptable limit, indicating that the PTES is no longer economically viable.

These results highlight the critical sensitivity of the economic viability of long-term thermal energy storage systems to the selected reference energy source and its associated cost. Consequently, when evaluating thermal storage investments, careful consideration of the local energy supply context and fuel cost structures is essential.

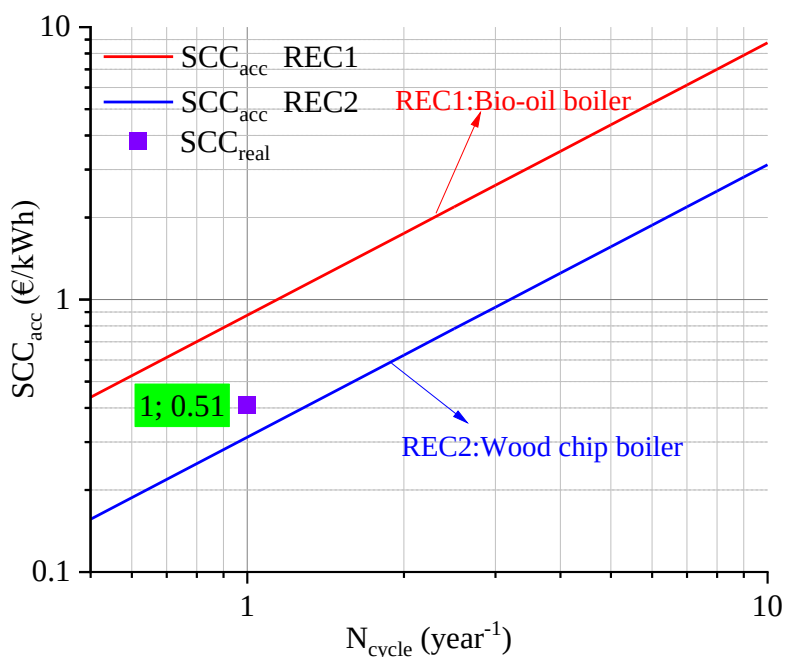


Figure 7-8: Maximum acceptable storage capacity costs (SCC_{acc}) under two REC scenario and realised storage capacity costs (SCC_{real}) for the PTES in Marstal, Denmark.

7.3.1.3 Borehole thermal energy storage in Brædstrup, Denmark

Figure 7-9 shows the aerial view of the district heating plant located in Brædstrup, Denmark, highlighting its integrated energy generation and storage components. The district heating plant (P9) is currently in operation. The facility consists primarily of a large-scale solar thermal collector field, divided into two installations: the first, covering 8,012 m², was established in 2007, and the second, covering 10,600 m², was added in 2012. Heat storage is provided by both short-term and seasonal storage systems. Short-term storage includes two insulated steel tanks with volumes of 5,500 m³ and 2,000 m³, respectively. The seasonal storage solution is a 19,000 m³ pilot BTES system, located near the solar collector arrays. Additionally, the plant includes supplementary heat production units comprising heat pumps, electric boilers, generators, and gas boilers to ensure stable heat delivery to the local district heating network [78].

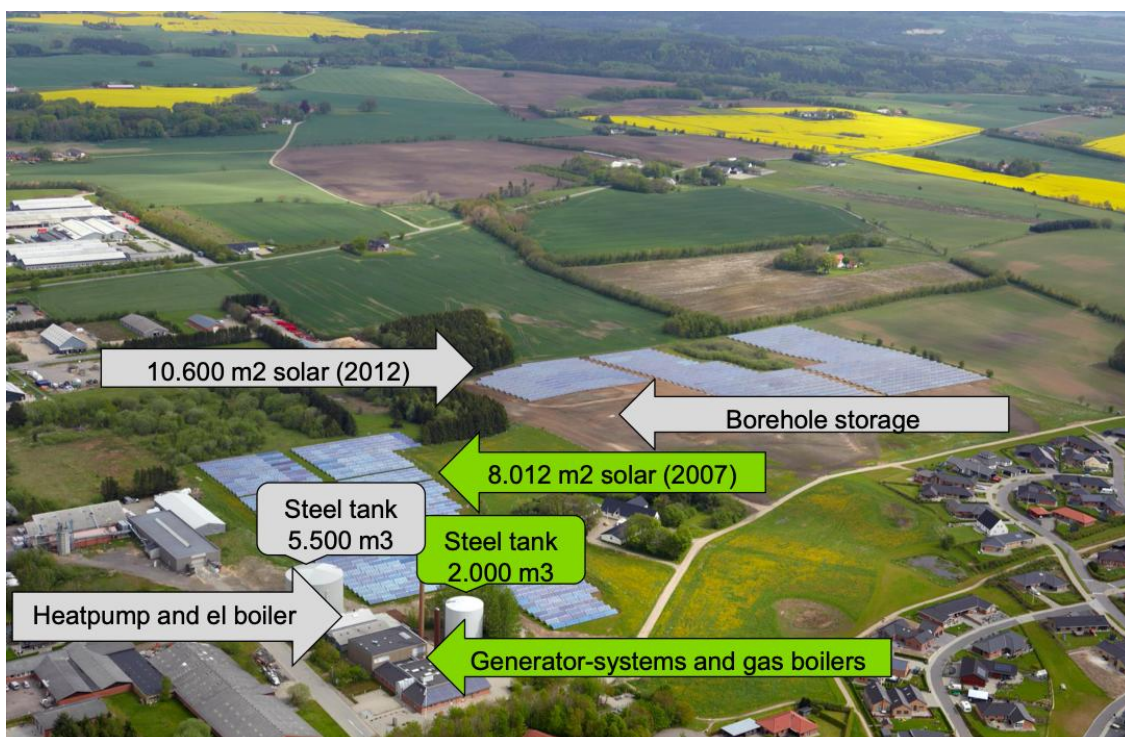


Figure 7-9: Aerial view of the district heating plant in Brædstrup, Denmark [79].

Table 7-7 summarises the economic and technical parameters of the BTES system in Brædstrup. An interest rate of 5% and a payback period of 13.4 years yield an annuity factor of 0.104. The number of full storage cycles per year is 0.6. The system's reference energy source is natural gas, with a fuel cost of 0.07 €/kWh. According to data provided by PlanEnergi, the *INC* of the PTES is € 260,000, and the corresponding *SC* is 480,000 kWh.

Table 7-7. The economic and technical parameters of the BTES system in Brædstrup, Denmark.

Interest rate	Payback period	<i>ANF</i>	N_{cycle}	<i>REC</i> (Natural gas, €/kWh)	<i>INC</i> (€)	<i>SC</i> (kWh)
5%	13.4	0.104	0.6	0.07	260,000	480,000

Figure 7-10 compares the maximum acceptable storage capacity cost (red line) derived using the top-down method with the realised storage capacity cost (blue square) for the BTES system in Brædstrup, Denmark. Both parameters are plotted as functions of the annual number of full storage cycles on a double-logarithmic scale. From Figure 7-10, at the current operating condition of 0.6 cycles per year, the realised storage cost of the BTES is approximately 0.54 €/kWh, exceeding the corresponding maximum acceptable limit (about 0.40 €/kWh). This indicates that under its current usage scenario, the system does not fully meet the defined economic criteria, as the realised cost exceeds the maximum acceptable cost. However, if the annual storage cycles were increased to approximately 0.8 per year, the realised storage cost would match the maximum acceptable cost, achieving a break-even

point (red circle) of economic viability. Thus, even a moderate increase in the utilization frequency significantly improves the system's economic attractiveness.

The observed discrepancy could be attributed to the BTES system being oversized relative to its current thermal load and usage pattern. Oversizing results in underutilization of storage capacity, thereby increasing specific investment costs and negatively affecting economic performance. Therefore, proper sizing of the storage capacity during the initial design phase is crucial. A carefully matched storage size—aligned closely with actual demand and expected thermal cycles—can significantly enhance economic viability and ensure efficient utilization of investment resources.

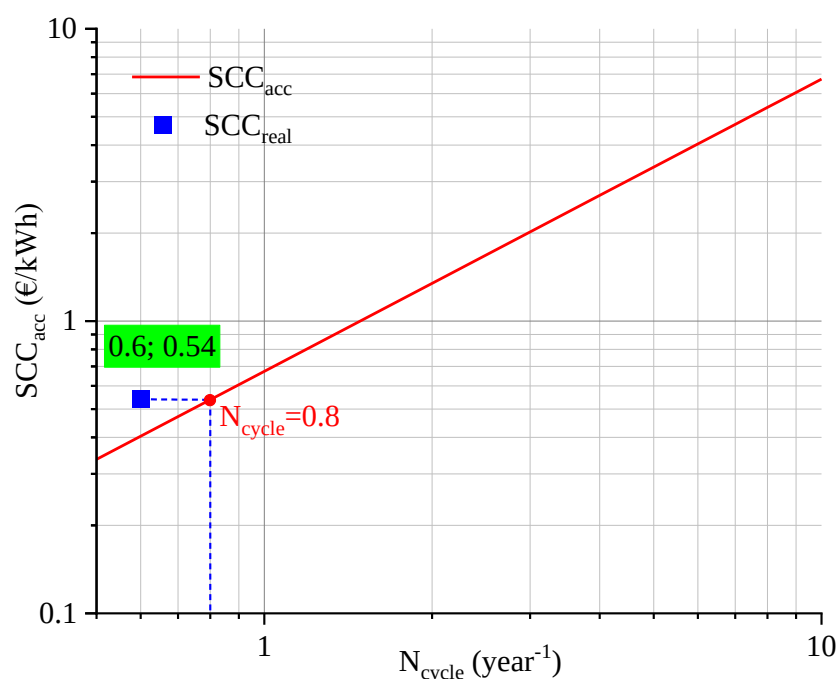


Figure 7-10: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}) for the BTES in Brædstrup, Denmark.

7.3.1.4 Underground hydrogen storage in Gampern, Austria

As renewable energy sources expand, power-to-gas technology plays a critical role in addressing the mismatch between energy supply and demand. The process converts surplus electricity from renewable energy sources (e.g., solar and wind energy) into hydrogen, a chemical energy carrier, enabling large-volume energy storage. The key steps in this technology include: 1) Electrolysis, where electricity from renewable sources splits water into hydrogen and oxygen; 2) Hydrogen storage, where the generated hydrogen is stored safely in underground reservoirs for later use.

Underground Sun Storage 2030 (P14) is an Austrian lighthouse demonstrator that aims to prove the safe, seasonal and large-scale underground storage of renewable energy in the form of hydrogen. Led by RAG Austria AG and supported by multiple partners, the project explores the technical and economic foundations for a secure hydrogen-supply system by converting surplus solar and wind

power into green hydrogen and storing it in depleted natural-gas reservoirs. Running until 2025, it is the world's first real-scale field test of pure-hydrogen storage in a porous gas field near Gampern in Upper Austria [80].

Figure 7-11 shows the schematic of the underground hydrogen storage system. The experimental wells are drilled into a depleted natural-gas reservoir, which served as the test cavern for injecting, storing and re-extracting the hydrogen. The project has advanced to a real-scale field trial, focusing on the storage of hydrogen in former natural gas reservoirs. This innovative approach aims to utilise existing infrastructure to store hydrogen efficiently, ensuring its availability during periods of high demand.

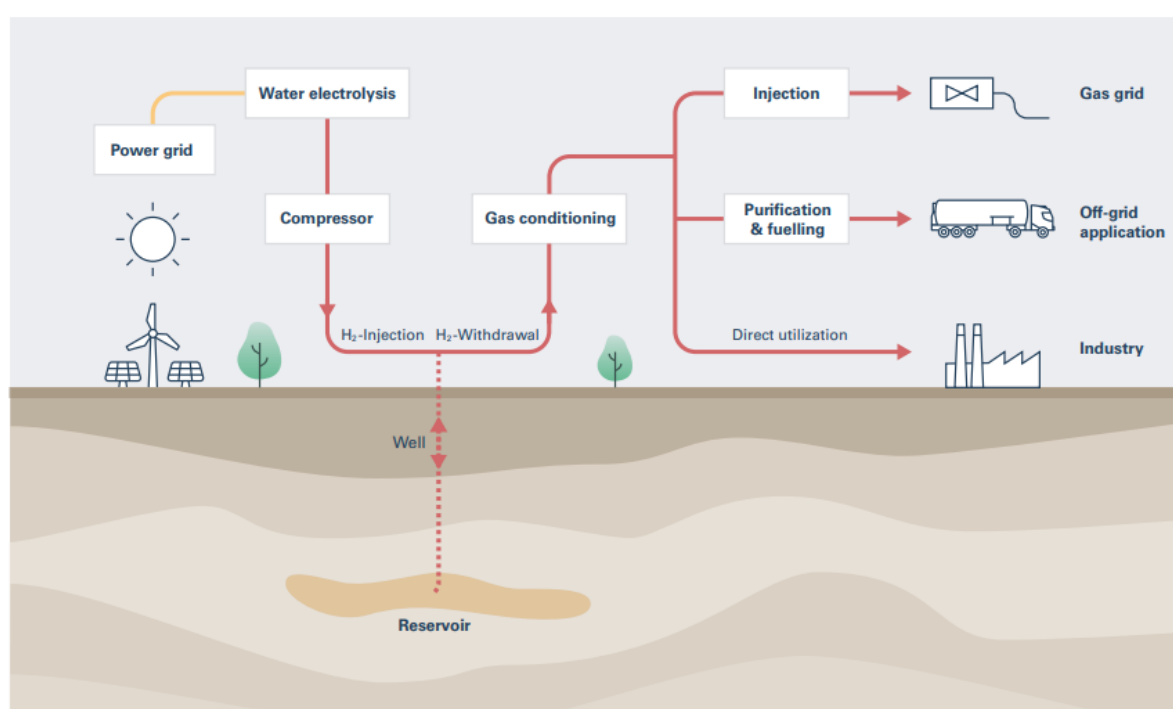


Figure 7-11: Schematic drawing of the underground hydrogen storage system in Pilsbach, Austria [81].

Table 7-8 summarises the economic and technical parameters of the hydrogen storage system in Gampern, Austria. Because the project is used for industry sector, the assumed interest rate is 5% and a payback period is 3 years, resulting in an *ANF* of 0.37. The annual storage cycle is 1, and the *REC* is 0.04 €/kWh based on the cost of natural gas for industry users in Austria. The *CAPEX* of the project is 32.5 €/kW, and the *FDD* is 2300 hours, implying that the realised storage capacity cost equals 0.014 €/kWh.

Table 7-8. The economic and technical parameters of the hydrogen storage system in Gampern, Austria.

Interest rate	Payback period	<i>ANF</i>	N_{cycle}	<i>REC</i> (Natural gas, €/kWh)	<i>CAPEX</i> (€/kW)	<i>FDD</i> (h)
10%	5	0.26	1	0.04	32.5	2,300

Figure 7-12 illustrates the comparison among the maximum acceptable storage capacity cost, the realised storage capacity cost, and the total cost of the hydrogen storage system. The SCC_{acc} calculated using the top-down approach is around 0.16 €/kWh, significantly higher than the SCC_{real} of 0.014 €/kWh. This margin clearly indicates that the hydrogen storage system is highly economically feasible under the given reference energy cost scenario and current operational conditions. In addition, according to [82], a combination scenario (wind-surplus absorption + negative-control energy + spot-market purchases) operating 6 000 h/year, yielding total production cost of 0.13 €/kWh for the hydrogen. This total cost includes the capital and operating costs of electrolysis, compression, underground reservoir use, and the filling-station/grid-injection interface. It therefore represents the levelised cost per kWh of energy supplied from storage, which is around 10 times the realised storage capacity cost. Besides, the total cost is still lower than the accordingly SCC_{acc} , this result underlines the strong economic potential of hydrogen storage technology utilise existing infrastructure (former natural gas reservoirs).

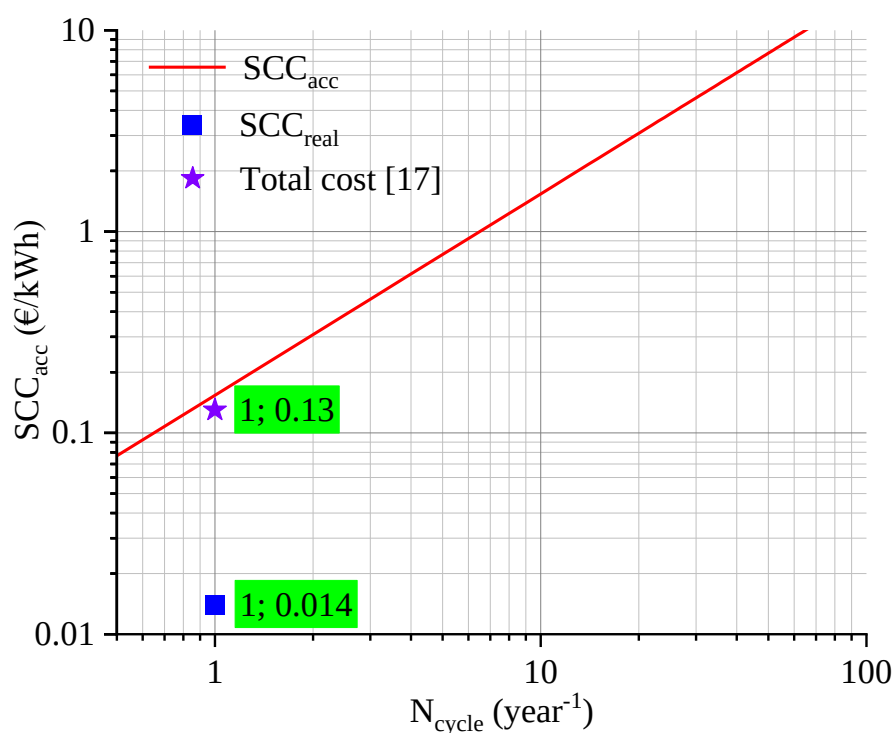


Figure 7-12: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}), and the total cost for hydrogen storage system in Gampern, Austria.

7.3.2 Short-term energy storage

7.3.2.1 Sea salt battery storage in the living lab of TU Delft

Figure 7-13 shows the concept map of the FLEXINet project in the living lab of the TU Delft. The FLEXINet project (P5) focuses on the development of a hybrid energy storage system designed for the simultaneous storage of heat and electricity in an energy-neutral residential setting. The system

integrates various storage technologies, including an innovative sea salt battery developed by Dr. Ten BV [83]. This battery, primarily composed of naturally sourced minerals, carbon electrodes, and sea salt, represents a clean, cost-effective, and environmentally friendly solution for stationary storage of renewable energy, such as solar or wind-generated electricity. Moreover, the battery can function as an electric vehicle charging station. Research conducted at TU Delft confirms the battery's low environmental impact due to its composition of materials with minimal hazard ratings. This hybrid storage concept thus offers significant potential for sustainable, efficient, and affordable residential energy storage applications.



Figure 7-13: The concept map the Flexinet project in the living lab of the TU Delft [84].

Table 7-9 summarises the economic and technical parameters of the sea salt battery storage system installed at TU Delft. The economic parameters include an interest rate of 5%, a payback period of 3 years, and an *ANF* of 0.37. Technically, the battery system is characterised by an exceptionally high annual cycle count ($N_{\text{cycle}} = 4,380$), and the *REC* is set at 0.4 €/kWh based on the cost of natural gas in Netherlands. The reported *CAPEX* ranges from 190 to 390 €/kW, and the *FDD* of the battery is 1 hour, implying that the realised storage capacity cost is directly equal to the *CAPEX* values (i.e., between 190 and 390 €/kWh).

Table 7-9. The economic and technical parameters of the sea salt battery storage system in TU Delft.

Interest rate	Payback period	<i>ANF</i>	N_{cycle}	<i>REC</i> (Natural gas, €/kWh)	<i>CAPEX</i> (€/kW)	<i>FDD</i> (h)
5%	3	0.37	4,380	0.04	190-390	1

Figure 7-14 illustrates the comparison between the maximum acceptable storage capacity cost and the realised storage capacity cost for the sea salt battery system at TU Delft. At the operating condition (4,380 cycles per year), the SCC_{acc} calculated using the top-down approach is around 500 €/kWh, significantly higher than the SCC_{real} of between 190 and 390 €/kWh. This margin clearly indicates that the sea salt battery system is highly economically feasible under the given reference energy cost scenario and current operational conditions. The results underline the strong economic potential of

short-term, high-frequency storage technologies such as the sea salt battery. Due to their frequent cycling and correspondingly high annual energy throughput, such systems can tolerate considerably higher specific investment costs, making them attractive from both economic and environmental perspectives.

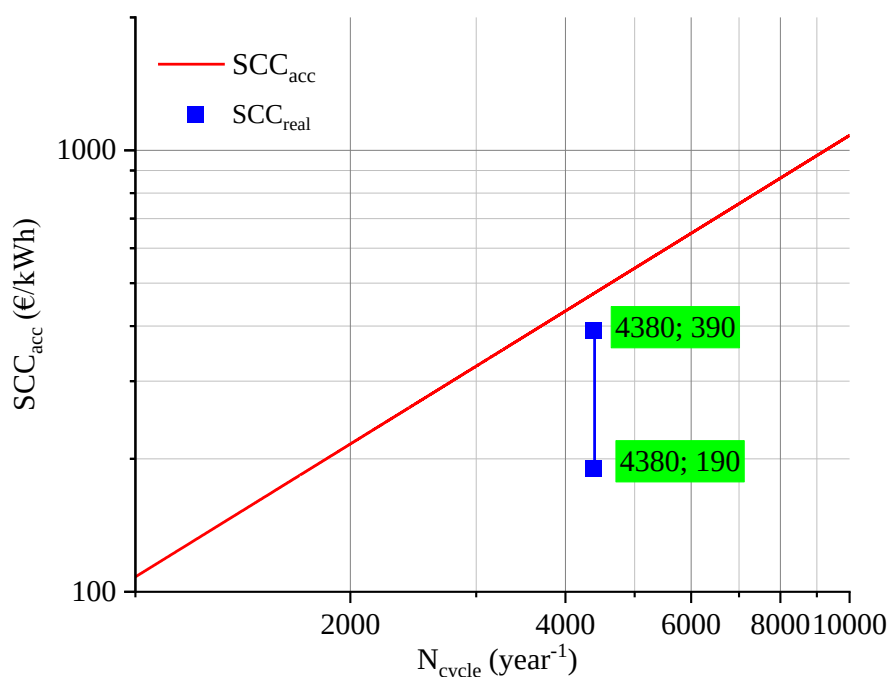


Figure 7-14: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}) for sea salt battery storage system in TU Delft.

7.3.2.2 Compressed Air Energy Storage in the UK

Figure 7-15 illustrates the working principle of a Storelectric CAESTM system. The CAESTM technology uses a thermal energy management and storage system to recover lost heat from the compression process and reuse it in the power cycle [85]. From Figure 7-15, the system (P6) begins by using surplus electricity—typically from renewable energy sources like wind or solar power—to operate an air compressor. This compressor draws in ambient air and compresses it, increasing its pressure and temperature. The pressurised air is then directed into a large underground salt cavern, which serves as the storage medium. These caverns provide a cost-effective and geologically stable environment for storing high-pressure air over long periods (i.e., 30+ years with little efficiency loss on mechanical and up to 100 years on underground caverns). Once stored, the compressed air remains in the cavern until electricity is needed. When demand for electricity arises, the stored air is released and brought back to the surface. Before expansion, the air is heated—either by recovering heat from the initial compression stage or through external thermal sources. This reheated air then passes through an expander or turbine, where it expands and drives a generator to produce electricity. The entire cycle is supported by a heat management system that improves the system's overall efficiency. The

proposed processes have been analysed and specific proven equipment and designs that will deliver it were identified, corroborating an efficiency of 62.3% for a 40 MW pilot plant.

The University of Chester in the UK is building the first demonstration and test facility with Storelectric CAES™ system. It is being built at the university's Thornton Science Park and will also have a secondary role of proving the concept of 100% renewable energy back up at a building scale (e.g., for hospitals). According to Storelectric, several projects are under construction and expected to become operational in the coming years in Cheshire. In parallel with this initial step, work continues developing the first commercial grid-scale project, utilizing five caverns that are ready for operation and capable of providing 20 MW for 50 hours [86].

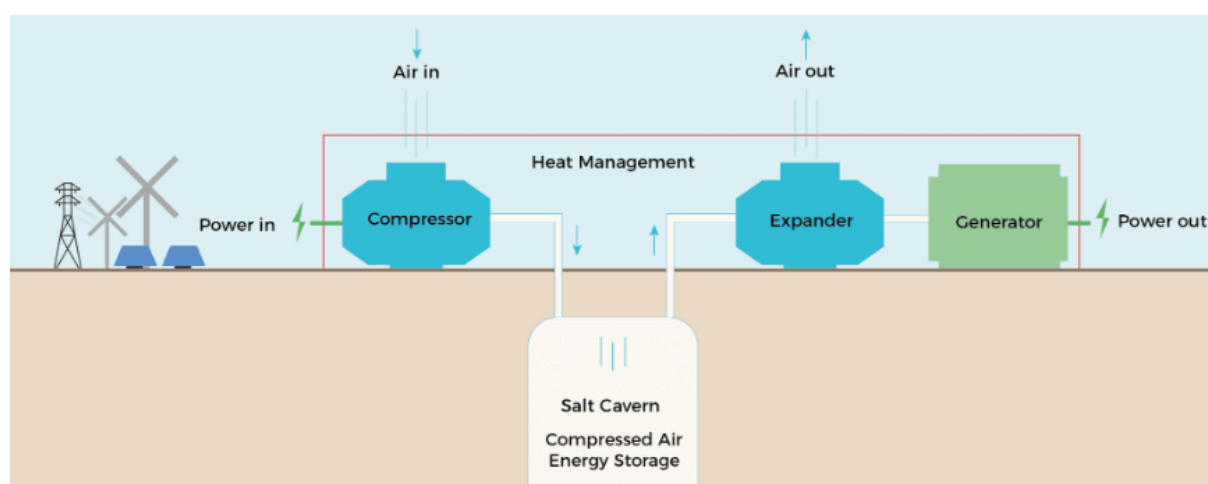


Figure 7-15: Schematic drawing of Storelectric CAES™ concept in the UK [86].

Table 7-10 presents the economic and technical parameters of the Storelectric CAES™ system (40 MW pilot plant) in the UK. The economic assumptions include an interest rate of 5% and a payback period of 20 years, resulting in an *ANF* of 0.08. The system operates at 720 full storage cycles per year. The *REC* provided by the survey respondent is 0.09 €/kWh, though the specific type of reference energy was not explicitly identified. The capital expenditure for this CAES system is 1,320 €/kW, and its full discharge duration is 5 hours.

Table 7-10. The economic and technical parameters of the Storelectric CAES™ system in the UK.

Interest rate	Payback period	<i>ANF</i>	N_{cycle}	<i>REC</i> (€/kWh)	<i>CAPEX</i> (€/kW)	<i>FDD</i> (h)
5%	20	0.08	720	0.09	1,320	5

Figure 7-16 compares the maximum acceptable storage capacity cost, with the realised storage capacity cost for the Storelectric CAES™ system. At 720 cycles per year, the realised storage capacity cost for this CAES system is approximately 264 €/kWh, derived by dividing the *CAPEX* by the *FDD*. At the same cycle frequency, the calculated SCC_{acc} from the top-down approach is roughly 800 €/kWh.

Since the realised cost (blue square) lies significantly below the accordingly SCC_{acc} threshold, the system demonstrates strong economic viability under the provided reference energy cost scenario.

Overall, these results highlight the favourable economics of the Storelectric CAES™ system in the UK under the assumed economic conditions. The substantial margin between the realised cost and maximum acceptable cost implies robust economic performance, making this CAES solution particularly attractive for frequent, short-term energy storage applications.

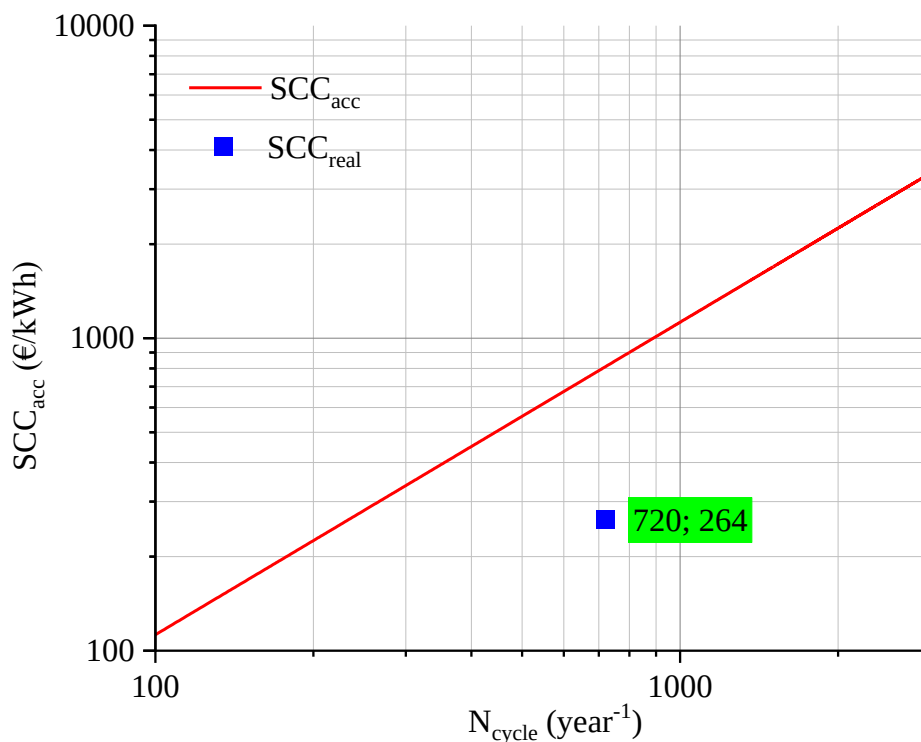


Figure 7-16: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}) for Storelectric CAES™ system in the UK.

7.3.2.3 Pit Thermal Energy Storage in Høje Taastrup, Denmark

The PTES in Høje Taastrup, Denmark, with a volume of 70,000 m³, was the first large-scale PTES to be operated as a short-term storage (storage cycle of 1-2 weeks). The storage (P7) was connected to the Copenhagen district heating grid and started operating in February 2023. An overview of the PTES is presented in Figure 7-17. Finding a sufficiently large plot of land near Copenhagen, close to existing district heating infrastructure, and outside the city zoning was challenging. Therefore, the selected plot of land had some restrictions, i.e., a highway to the south and a water pipe to the north, which dictated the shape and size of the PTES [87].

The developed PTES was jointly owned by the companies VEKS and Høje Taastrup Fjernvarme a.m.b.a. VEKS is a transmission company that provides district heating to 17 distribution companies in the western part of Copenhagen. Høje Taastrup Fjernvarme a.m.b.a. is a consumer-owned distribution company delivering district heating in the municipality of Høje Taastrup. Notably, the expenses related

to the construction and operation of the storage were shared among all the major heat producers in the Copenhagen district heating network according to their individual expected long-term economic benefits [72].



Figure 7-17: Aerial view of the PTES in Høje Taastrup, Denmark [87].

Table 7-11 summarises the economic and technical parameters of the large-scale PTES system in Høje Taastrup, Denmark. The interest rate is 5%, with a payback period of 11.6 years, resulting in an *ANF* of 0.12. The PTES system operates with relatively high annual storage cycles, ranging from 25 to 30 cycles per year. The *REC* considered in the evaluation is electricity priced at 0.10 €/kWh. The reported *INC* for the project is approximately € 12,000,000, and the total *SC* is 3,300 MWh.

Table 7-11. The economic and technical parameters of the PTES in Høje Taastrup, Denmark.

Interest rate	Payback period	<i>ANF</i>	N_{cycle}	<i>REC</i> (Electricity, €/kWh)	<i>INC</i> (€)	<i>SC</i> (kWh)
5%	11.6	0.12	25-30	0.10	12,000,000	3,300,000

Figure 7-18 presents a comparison between the maximum acceptable storage capacity cost and the realised storage capacity cost calculated from actual collected data for the Høje Taastrup PTES system. At the operational range of 25 to 30 cycles per year, the realised storage capacity cost is about 3.64 €/kWh, while the corresponding SCC_{acc} is approximately 11 €/kWh. The clearly lower realised cost relative to the maximum acceptable limit demonstrates that the Høje Taastrup PTES is economically feasible under these conditions.

However, compared to other PTES systems in Denmark such as those in Marstal and Dronninglund, the realised storage capacity cost in Høje Taastrup is significantly higher. Several factors contribute to this cost difference. Firstly, the rise in construction material prices in recent years has substantially increased the overall capital cost. Secondly, this PTES is the first large-scale facility designed explicitly for short-term thermal energy storage applications, operating consistently at high temperatures

around 90 °C. Such high-temperature operation necessitates sophisticated design practices and the use of specialised insulation materials that can withstand prolonged thermal stress, further elevating costs. Additional contributing factors could include site-specific challenges, such as more complex geological conditions requiring more extensive groundwork or excavation, stricter regulatory compliance due to proximity to the Copenhagen urban areas, and potentially higher labour or equipment costs associated with pioneering implementation practices for short-term, high-temperature PTES. These factors collectively explain why the realised investment cost for the Høje Taastrup PTES system is higher compared to previously built seasonal PTES facilities.

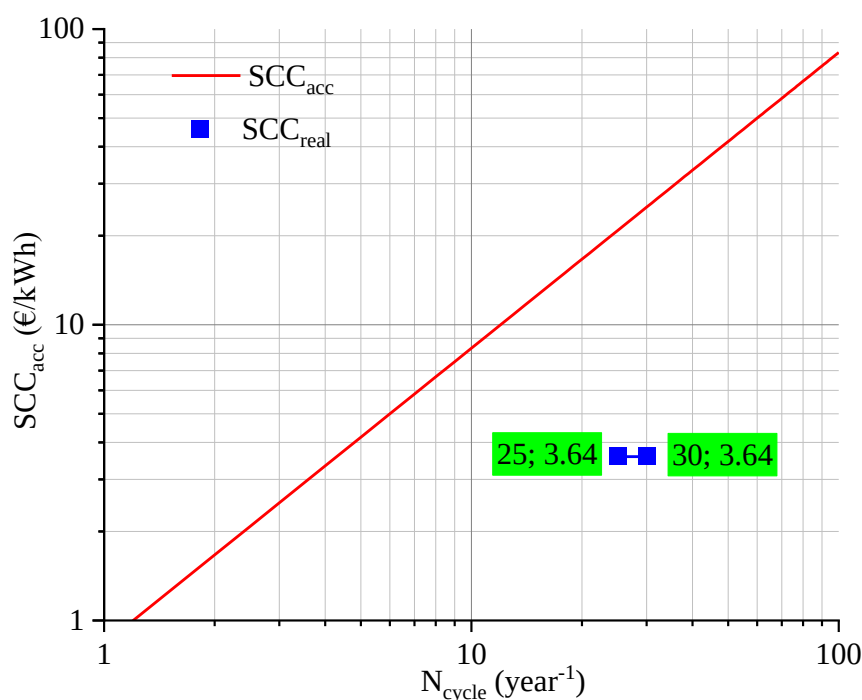


Figure 7-18: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}) for the PTES system in Høje Taastrup, Denmark.

7.3.2.4 Sensible heat storage in DTU Science Park, Hørsholm

Figure 7-19 shows the working principle RockStore project in the DTU Science Park, Hørsholm. This project (P10) is developed by Heliac company and utilises granite rocks in steel tanks to store heat up to 300 °C, sourced from waste heat, Heliac solar fields, or excess renewable electricity. The system uses eco-friendly oil and standard heat exchangers to charge and discharge heat as needed, with options for power generation via steam turbines in larger setups, providing a versatile energy storage solution for various applications. This STES ensures green power, district heating, and process heat for consumers and industry during periods with low renewable energy availability [88].

The project aims to scale up and demonstrate a new low-cost, flexible energy storage technology for on-demand heat and power generation. The Danish-patented invention, featuring high-efficiency heat transport, standard components, and natural materials like stone and organic oil, achieves a low large-

scale bill of materials cost and high scalability. The project includes designing and constructing a 20–40 MWh energy storage system, integrating it into a power plant, and demonstrating the recycling of high-temperature fluctuation heat for district heating and electricity.

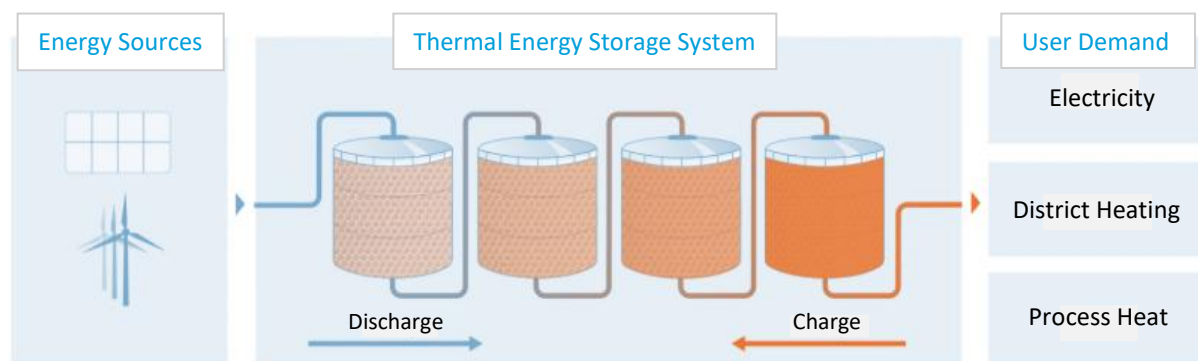


Figure 7-19: Schematic drawing of the Rockstore working principle [88].

Table 7-12 presents the economic and technical parameters of the Rockstore STES project located at the DTU Science Park (DTU SP) in Hørsholm. The assumed interest rate is 5%, and according to the respondent questionnaire, the payback period ranges between 3 and 8 years, leading to a corresponding *ANF* ranging from 0.15 to 0.37. The system is operated with relatively high annual cycles (50–100 cycles per year), and the selected *REC* is electricity priced at 0.10 €/kWh. The *SC* is reported as 300,000 kWh, although the respondent did not provide detailed *INC* data. However, official promotional materials from the company Heliac indicate that the RockStore technology achieves significantly lower investment costs compared to traditional battery systems, approximately 10–15 €/kWh [89].

Table 7-12. The economic and technical parameters of the Rockstore project at the DTU SP.

Interest rate	Payback period	<i>ANF</i>	N_{cycle}	<i>REC</i> (Electricity, €/kWh)	<i>INC</i> (€)	<i>SC</i> (kWh)
5%	3-8	0.15-0.37	50-100	0.10	/	300,000

Figure 7-20 illustrates the comparison between the maximum acceptable storage capacity costs considering two scenarios based on different annuity factors ($ANF = 0.15$ and $ANF = 0.37$), and the realized storage capacity costs for the Rockstore project at DTU SP, Hørsholm. At the project's operational range of 50 to 100 annual cycles, the realized costs reported by Heliac (10–15 €/kWh) are plotted as purple squares. These realized storage costs are clearly below both SCC_{acc} curves (red line for $ANF = 0.37$ and blue line for $ANF = 0.15$), highlighting the strong economic attractiveness of the Rockstore technology under either financial scenario.

The results suggest that Heliac's STES technology provides substantial economic benefits, achieving a realized investment cost significantly lower than the maximum acceptable thresholds for both

conservative and optimistic payback expectations. Such low realized costs, combined with high operational flexibility, underscore RockStore’s promising potential as an economically viable alternative to conventional battery storage systems, particularly in applications requiring frequent charge–discharge cycles.

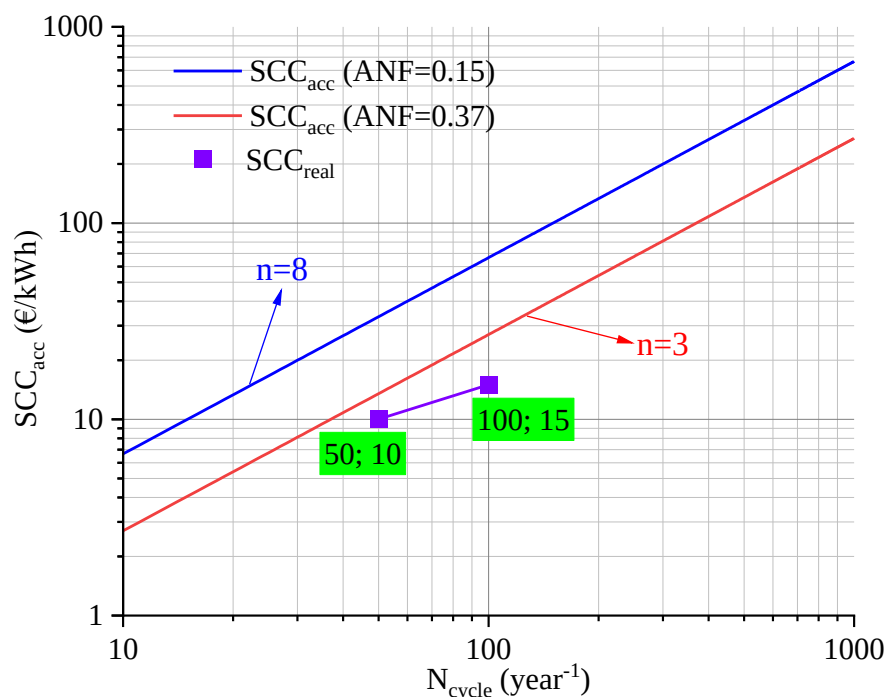


Figure 7-20: Maximum acceptable storage capacity costs (SCC_{acc}) and realized storage capacity costs (SCC_{real}) for the Rockstore project in the DTU Science Park, Hørsholm.

7.3.2.5 Latent heat storage in Gallneukirchen, Austria

Figure 7-21 shows the schematic drawing of the milk cooling plant in Gallneukirchen, Austria. The project (P11) aims to use surplus electricity through power-to-heat solutions and the application of ice storage technologies. From Figure 7-21, the project is solar ice storage for milk cooling, which comprises a milk cooler (25 kW, 600 L/day), an ice storage unit (1.7 m³, 110 kWh), a refrigeration machine (4 kW_{el}, 10 kW_{th}), and a PV system (34.4 kW_p). This system enables a degree of self-sufficiency of 98% and amortization in around seven years at a total cost of € 42,000. Ice storage tanks can also be used for heating and cooling by connecting them to the evaporator of a heat pump. These systems offer a high energy potential (70 kWh_{th}/m³) and can be used for direct cooling and hot water in summer [90]. In addition, ice storage systems are not limited to cooling applications; they can also be used to provide heating and hot water. By integrating with photovoltaic and heat pump technologies, they offer a flexible and efficient solution for energy management, ensuring optimal utilization of renewable electricity and reducing dependency on grid power.

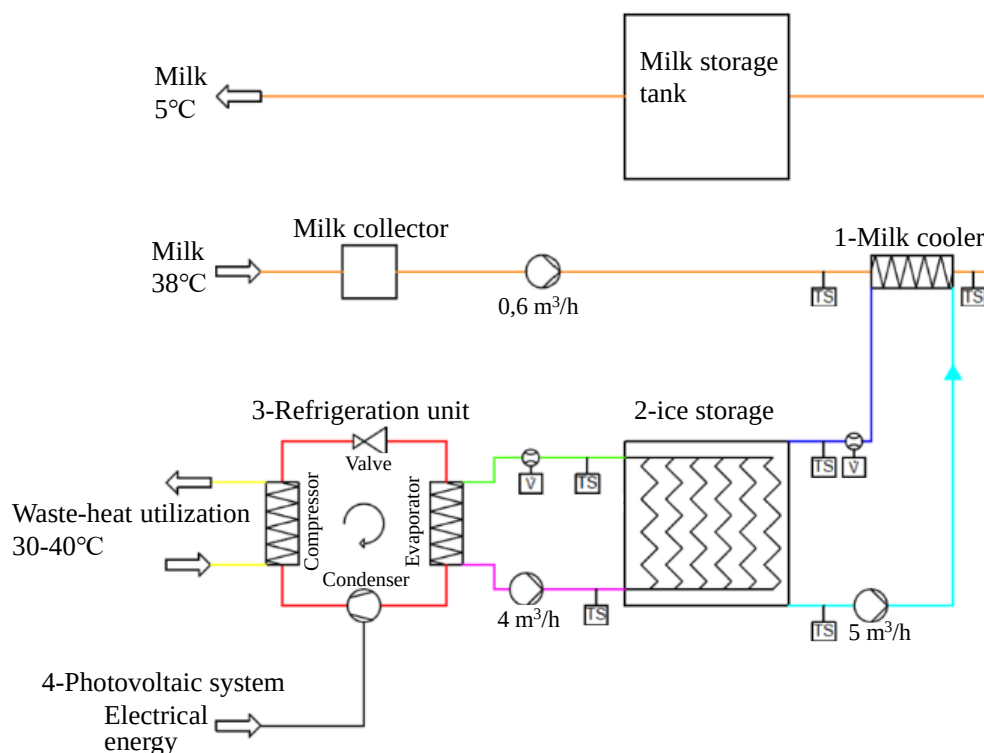


Figure 7-21: Schematic drawing of the milk cooling plant in Gallneukirchen, Austria [91].

Table 7-13 summarises the economic and technical parameters of the LHTES system located in Gallneukirchen, Austria. Due to the commercial application, the system is assessed with a relatively high interest rate of 10%, and a payback period of 7 years, resulting in an *ANF* of 0.21. The annual storage cycles range significantly, from 100 to 365 cycles per year. The provided *REC* is notably high (470 €/kWh), as the respondent identified electric batteries as the reference energy source. The reported *INC* for the system is 42,000 €/kW, with a *SC* of 100 kWh.

Table 7-13. The economic and technical parameters of the LHTES system in Gallneukirchen, Austria.

Interest rate	Payback period	<i>ANF</i>	N_{cycle}	<i>REC</i> (Electric battery, €/kWh)	<i>INC</i> (€/kW)	<i>SC</i> (kW)
10%	7	0.21	100(full)- 365 (partial)	470	42,000	100

Figure 7-22 compares the maximum acceptable storage capacity cost with the realised storage capacity cost of the LHTES project in Gallneukirchen. The realised cost is approximately 420 €/kWh, consistent across the operating cycle range of 100 to 365 cycles per year. Notably, the realised storage cost is substantially lower than the calculated maximum acceptable cost. This large margin primarily arises because the reference energy selected by the questionnaire respondent (electric battery storage) is priced very high, thus significantly elevating the allowable investment threshold. Additionally, the actual operational scenario of the LHTES project involves using surplus electricity from photovoltaic

generation for ice-based thermal storage. Consequently, the effective energy cost is considerably lower, further enhancing economic viability.

These results indicate that the Gallneukirchen LHTES project exhibits exceptional economic attractiveness under the selected reference conditions. However, the substantial gap between realised and acceptable costs also highlights the importance of carefully selecting reference energies and accurately representing actual operational practices in economic evaluations.

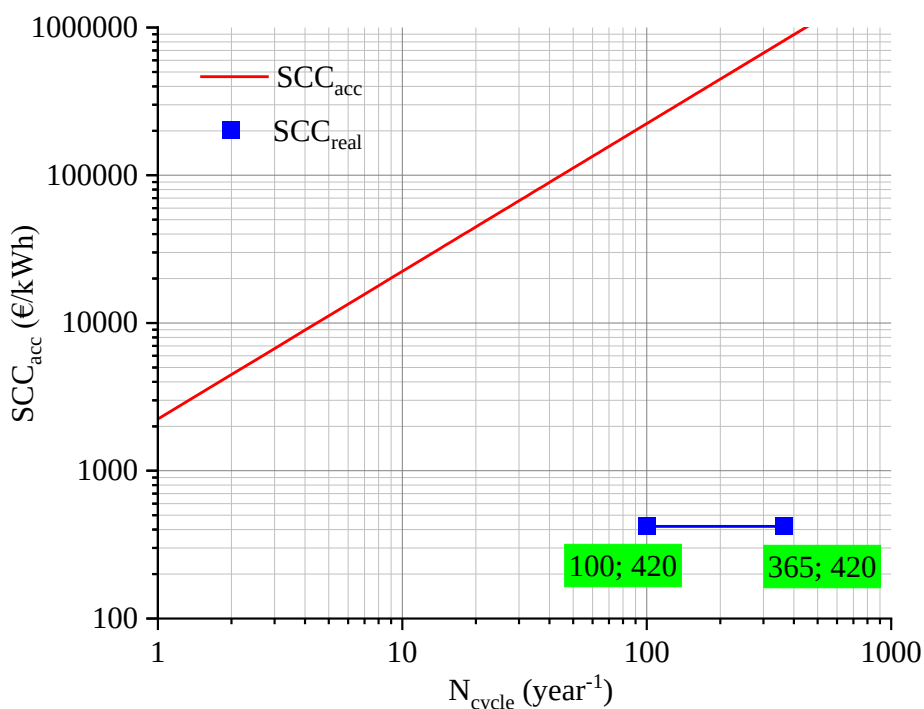


Figure 7-22: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}) for the LHTES project in Gallneukirchen, Austria.

7.3.2.6 Sensible thermal storage in Budapest, Hungary

This STES project in Budapest became operational in 2022 and was integrated into the city's district heating network. The installation serves as a Power-to-Heat demonstrator that uses the existing hot-water district heating infrastructure as a thermal storage medium. Specifically, a modular array of electric boilers (one rated at 5 MW, one at 1 MW, and four at 1.5 MW each) has been deployed at central heat plants or nodal points of the Budapest district heating grid [92]. These resistance heaters use surplus renewable electricity (from wind or solar) to heat water, which is then fed into the district heating system's supply line via heat exchangers. In essence, excess electrical energy is converted into sensible heat stored in the water circulating through the network (and in any attached hot-water storage tanks).

These electric boilers can be dispatched in parallel with great flexibility, allowing operators to match the number of active boilers to the available surplus power and the instantaneous heating load. During times of excess generation (e.g. windy nights or sunny off-peak hours), the district heating water is

heated above its normal supply temperature (charging mode). During times of high heat demand or high electricity prices, the stored heat is used (discharging mode) and gas or other boilers can be throttled down [92]. This not only cuts emissions by substituting electricity (which in Hungary's grid is increasingly from renewable sources) for gas, but also enhances grid stability by absorbing fluctuations. This effectively uses the district heating pipework (and any ancillary hot-water tanks) as a distributed thermal reservoir for sensible heat storage. The concept demonstrates how existing district heating infrastructure can be adapted for energy storage and grid balancing. It showcases a path to decarbonise urban heating by using renewable electricity when available, storing it as heat in water, and thus reducing gas consumption and CO₂ emissions.

Table 7-14 summarises the economic and technical parameters of the STES demonstrator in Budapest. An assumed interest rate is 5%, and the payback period is 3 years according to the respondent, thus the *ANF* equals 0.37. Because the electric boilers are dispatched whenever surplus electricity is available, the operator did not specify a fixed annual cycle number; instead, the analysis assumes a variable *N_{cycle}* that depends on renewable-power availability. The *REC* is the regulated residential natural-gas tariff in Budapest—0.025 €/kWh—reflecting the fuel displaced by electric heating. The *CAPEX* of the modular boiler array is 92 €/kW, and the *FDD* is 2.4 h, giving a realised storage-capacity cost of 38.3 €/kWh.

Table 7-14. The economic and technical parameters of the STES project in Budapest, Hungary.

Interest rate	Payback period	<i>ANF</i>	<i>N_{cycle}</i>	<i>REC</i> (Natural gas, €/kWh)	<i>CAPEX</i> (€/kW)	<i>FDD</i> (h)
5%	3	0.37	*	0.025	92	2.4

* Charging cycle whenever excess power is made available.

Figure 7-23 shows the maximum acceptable storage capacity cost and the project's break-even point (blue circle). Because the respondent did not provide the exact annual cycles, the break-even point is plotted. From Figure 7-23, the installation should operate at about 567 full charge–discharge cycles per year before its realised cost falls below the economic threshold. If such a cycling frequency can be achieved, the project will reach an economic balance. From Table 7-14, because the *FDD* is only 2.4 hours, thousands of storage cycles can be completed within a single heating season in theory, and the project will have large economic benefits at this condition.

The results highlight both the strengths and the constraints of this STES project. On the positive side, the specific investment is low thanks to inexpensive resistance-boiler hardware and the use of the existing district-heating network as the thermal reservoir. On the limiting side, Hungary's highly subsidised gas tariff leaves little headroom for capital recovery, so economic success depends almost entirely on frequent charging from surplus renewables. Ensuring that high level of utilisation—through robust demand response and ample renewable power—will therefore be central to the project's long-term viability.

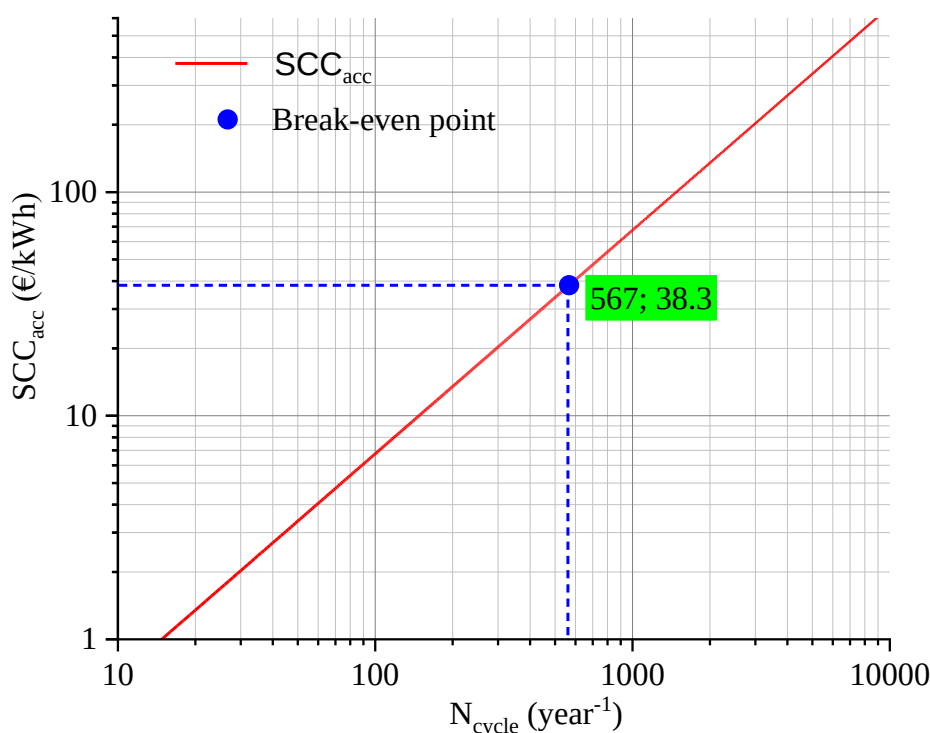


Figure 7-23: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}) for the STES project in Budapest, Hungary.

7.3.2.7 Pumped hydro storage in Ebensee, Austria

Energie AG company is investing around EUR 450 million in building a pumped-storage power plant in Ebensee, Upper Austria. Figure 7-24 shows the schematic drawing of the PHS plant. The pumped-storage power plant (P13) is planned as a cavern power plant at the foot of the “Großer Sonnstein” mountain with a variable-speed Francis turbine. The construction of a natural dam with a height of approx. 60 meters is planned for the headwater reservoir in the Rumitzgraben. Lake Traunsee will serve as the lower reservoir. In times of surplus electricity production, the water is pumped around 500 meters uphill, through a cavern housing the reversible pump-turbine, where it acts as an energy store that can be tapped at any time. When the demand for electricity increases, the water is routed back down again and converted into electrical energy by the turbine.

Construction of this project is due to start in October 2023 and will take four years, with trial operation scheduled for late 2027. To compensate for the volatility of electricity generation from sun and wind as part of a renewable future, industrial-scale storage capacity and flexibility is required in the form of pumped-storage power plants. The planned power plant will have a storage capacity of 1.32 million m^3 and an output of 170 MW. This means the operating time to generate electricity will be 10 full-load hours [93]. By responding to changes in demand and electricity generation with speed and flexibility, the planned power plant will deliver a major contribution to security of supply.

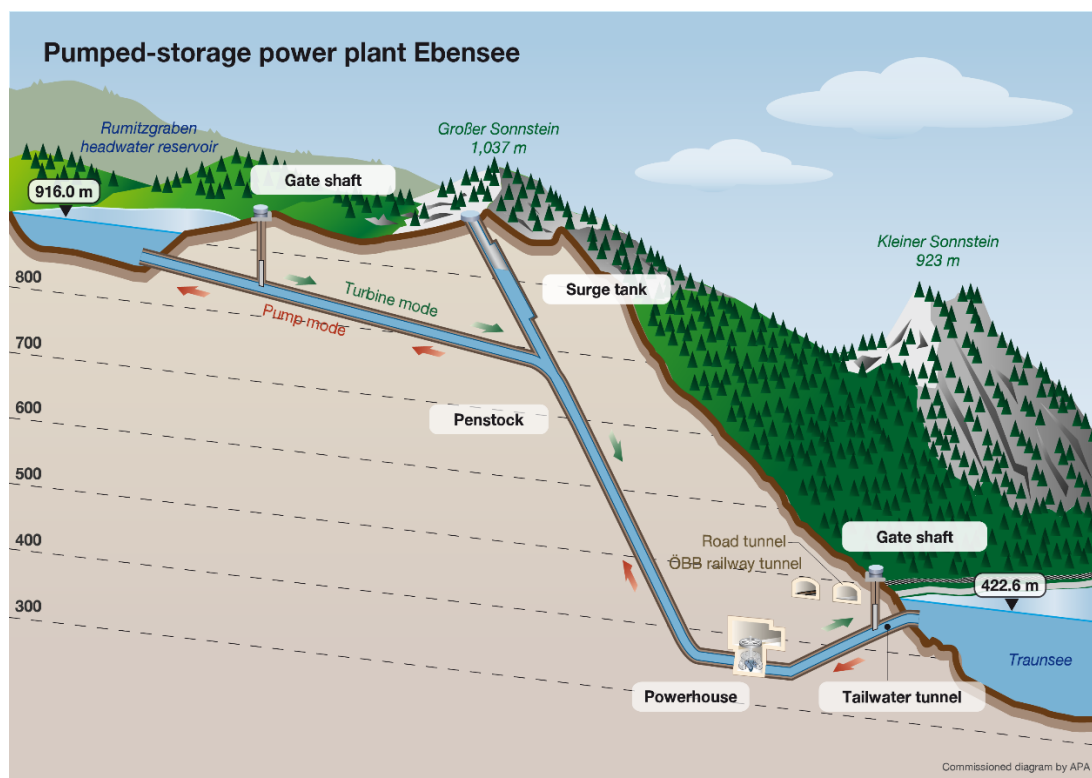


Figure 7-24: Schematic drawing of the Ebensee pumped hydro plant in Ebensee, Austria [93].

Table 7-15 provides the economic and technical parameters for the PHS plant located in Ebensee, Austria. The economic assumptions for the project include an interest rate of 5% and a payback period of 20 years, resulting in an *ANF* of 0.08. The plant has an annual number of full storage cycles of 230, and the *REC* considered for economic evaluation is electricity, priced at 0.1 €/kWh. The *CAPEX* for the system is around 2420 €/kW, and the plant has a full discharge duration of 9 hours.

Table 7-15. The economic and technical parameters of the PHS plant in Ebensee, Austria.

Interest rate	Payback period	<i>ANF</i>	N_{cycle}	<i>REC</i> (Electricity, €/kWh)	<i>CAPEX</i> (€/kW)	<i>FDD</i> (h)
5%	20	0.08	230	0.1	2420	9

Figure 7-25 compares the maximum acceptable storage capacity cost and the realised storage capacity cost of the Ebensee PHS project. At the annual cycle frequency of 230 cycles/year, the realised storage cost is approximately 269 €/kWh. The corresponding maximum acceptable storage capacity cost under the same operational conditions is approximately 288 €/kWh. The realised cost thus closely aligns with—but remains slightly below—the maximum acceptable cost threshold, indicating that the PHS project in Ebensee is economically viable under the given assumptions. However, due to the proximity of the realised cost to the economic threshold, the project's financial feasibility might be sensitive to variations in operational performance, maintenance costs, market electricity prices, or unforeseen investment increases.

In summary, the results confirm that the Ebensee PHS system, given current cost parameters and operating conditions, meets the defined economic criteria, but with limited margin, highlighting the importance of careful cost control and system optimization to ensure continued economic sustainability.

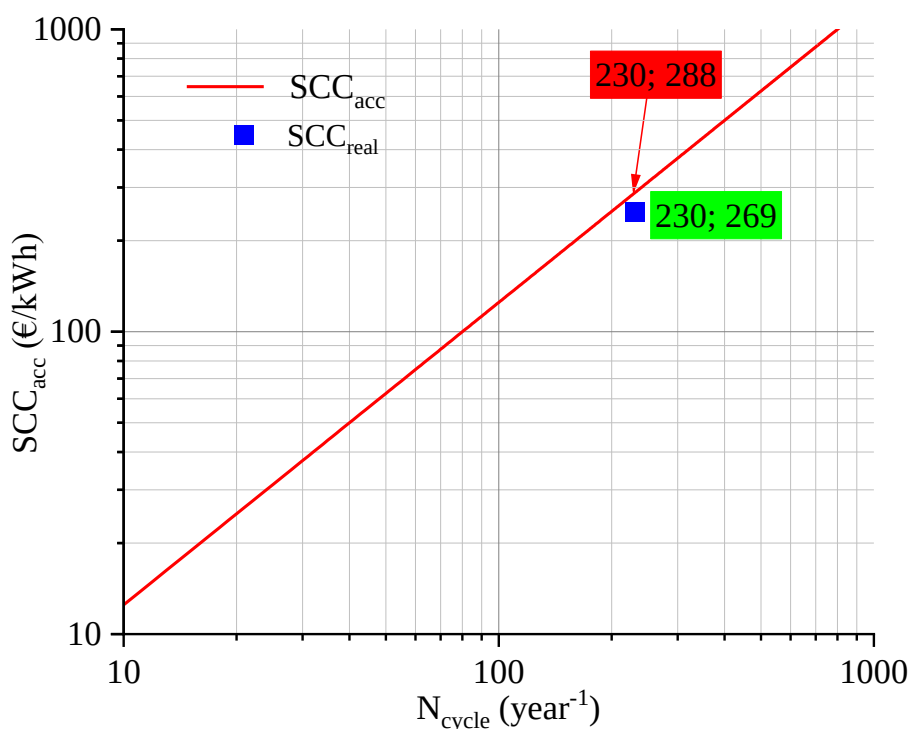


Figure 7-25: Maximum acceptable storage capacity costs (SCC_{acc}) and realised storage capacity costs (SCC_{real}) for PHS project in Ebensee, Austria.

7.3.3 Conclusions on evaluated energy storage cases

The comprehensive evaluation carried out under the IEA ES TCP Task 41 has provided clear insights into the economic viability of diverse energy storage technologies. This report systematically compared the maximum acceptable storage capacity costs with realised storage costs of each energy project, demonstrating significant variations driven primarily by technology type, annual cycling frequency, and regional market conditions.

- 1) Short-term energy storage systems (e.g., sea salt batteries, sensible heat storage, and latent heat storage) demonstrate robust economic viability due to their high frequency of annual cycling. Their higher utilization rates allow for higher permissible investment costs. While long-term energy storage solutions, such as PTES and BTES, are more economically sensitive due to their lower cycle frequency. PTES typically exhibits better economic performance compared to BTES, primarily due to lower specific investment costs.

- 2) Increasing the number of storage cycles is beneficial to improve economic performance. During the design phase of storage systems, the expected number of storage cycles can be used to assess the size of the system and its economic feasibility.
- 3) The economic attractiveness of storage systems is highly sensitive to regional reference energy costs. Systems evaluated against higher-cost reference energies (e.g., electricity or electric battery storage) consistently showed greater economic feasibility than those compared against lower-cost energies (e.g., natural gas or wood chip boilers). This underscores the importance of local energy pricing structures in determining the viability of storage investments, emphasizing tailored economic analyses specific to each region.
- 4) Innovative storage solutions, such as the Rockstore sensible heat storage and underground hydrogen storage, highlight the potential for leveraging low-cost materials and existing infrastructure, substantially reducing capital expenditure and enhancing scalability.
- 5) Projects integrating renewable energy sources (e.g., photovoltaic for latent heat storage) significantly improve economic outcomes by exploiting surplus energy. Utilizing surplus electricity via power-to-X or power-to-heat for short-term storage yields significant economic benefits.
- 6) Certain storage technologies, particularly large-scale seasonal storage (e.g., BTES and PHS), face strict economic constraints unless supported by subsidies or regulatory incentives due to their high initial capital costs and low cycle frequency. This is also the case because social benefits (whether strategic or, for example, in terms of alleviating grid congestion) are not yet sufficiently included into the business cases. Cost-effective design practices and accurate sizing relative to actual demand significantly enhance economic performance and resource efficiency.

Nevertheless, it should be noted that there is some uncertainty in the information provided in the questionnaire, as it is sometimes unclear whether the appropriate data/key figures were always provided.

7.4 Extension of the *maximum acceptable storage capacity cost* approach

7.4.1 Further development of the approach in collaboration with energy storage companies

The *maximum acceptable storage capacity cost approach* enables a simple initial assessment of the economic efficiency of energy storage systems for specific users. The analysis is based on the relationship between acceptable storage capacity costs, the frequency of storage charging and discharging, and the costs of the reference energy that is replaced by the storage system.

The calculation does not take into account operating and maintenance costs, costs for charging the storage systems, savings through reduced CO₂ emissions, etc.

The methodology was therefore further developed in the project. Discussions were held with companies active in the field of energy storage: on the one hand, to present the method for assessing the economic efficiency of energy storage systems and to recommend its use; on the other hand, to

obtain feedback from the companies and incorporate it into the further development of the method. The tool was discussed in detail with the companies and tested for their respective applications.

Among other things, this meant that operating and maintenance costs and costs for charging the storage facility were included in the analysis. To this end, the reference energy costs saved are adjusted accordingly, as the monetary savings per kWh of reference energy change accordingly due to operating/maintenance costs, costs for charging the storage facility and revenues from savings in CO₂ emissions.

One of the discussions focused on a large thermal energy storage facility integrated into a district heating network. The energy storage facility was planned in combination with a power plant in order to keep heat generation below a certain level. This made it possible to reduce the power plant capacity to be installed, thereby saving costs. Such savings were incorporated into the methodology by adjusting the investment costs of the storage facility to reflect investment costs saved elsewhere.

Ultimately, the discussions with the companies led to the methodology being divided into three different approaches. Depending on the specific application and business model, one of the three approaches is to be selected.

7.4.2 Three versions of the maximum acceptable energy storage cost approach

Approach (1): If a simple and rough economic assessment of an energy storage system is to be made, the original approach can be used (see section 7.1). Due to the small number of techno-economic parameters, it allows a quick initial assessment of the profitability of the energy storage system.

Approach (2): For a more in-depth assessment of the profitability of the energy storage system, the original approach has been expanded to include several techno-economic parameters. This approach should still be regarded as a simplification.

Approaches (1) and (2) are suitable if the main purpose of the energy storage system is to supply a certain amount of energy (heat, electricity, etc.) and thus avoid or reduce the use of alternative energy sources.

Approach (3): If the economic analysis of an energy storage system cannot be carried out on the basis of the reference energy saved, for example in the case of a battery storage system that sells grid services, it is helpful to focus on generated revenues. The third approach therefore makes it possible to use different revenues as the basis for assessing economic efficiency.

The three approaches of the model are referred to as follows: (1) 'reference-oriented', (2) 'extended reference-oriented' and (3) 'revenue-oriented'. The approaches are explained in detail below.

7.4.2.1 Reference-oriented version (the original approach)

Approach (1) has already been explained in section 7.1 and applied in section 7.3. This simplified model provides an initial impression of the profitability of a storage system compared to purchasing reference energy, which would be necessary without the installation of an energy storage system. It also provides an understanding of the profitability of the storage system depending on its investment costs and the number of cycles per year.

The equation used for the acceptable storage capacity cost SCC_{acc} is:

$$SCC_{acc} = \frac{REC}{ANF} \cdot N_{cycle} \quad (7-5)$$

For the realised storage capacity cost SCC_{real} is:

$$SCC_{real} = \frac{INC}{SC} \quad (7-6)$$

The result generated using approach (1) can be interpreted as follows, for example: If the realised storage capacity costs are significantly higher than the acceptable storage capacity costs, it is very unlikely that the storage system will be profitable, as operating costs have not yet been taken into account. If the realised storage capacity costs are within the range of or significantly below the acceptable costs, a more detailed analysis of the economic efficiency is recommended, for example using approach (2).

7.4.2.2 Extended reference-oriented version

Approach (2) adds the following parameters to approach (1) in order to make the economic assessment more detailed and realistic:

- Operating and maintenance costs (*OMC*) [EUR/kWh]: *OMC* takes into account the costs incurred for operating and maintaining the energy storage system. These costs are variable, as they are proportional to the use of the storage facility and therefore depend on the number of charging and discharging cycles.
- Charging cost (*CHC*) [EUR/kWh]: The charging cost indicates the cost per kWh for charging the storage facility. If, for example, charging via the electricity grid is planned, the price per kilowatt hour of electricity must be applied. If, on the other hand, a thermal energy storage system can be charged using waste heat at no additional cost, $CHC = 0$ EUR/kWh. Negative electricity prices, which may be available at certain times for charging the storage system, can also be represented by negative values for *CHC*.
- Total efficiency (round trip efficiency) *RTE* [-]: To estimate the actual costs for a complete charge of a storage unit, the *RTE* is to be taken into account. In an ideal storage unit with an

RTE of 100%, the total amount of energy charged into the storage unit is available for discharge and thus for actual use. In reality, this is not possible due to losses, for example through heat dissipation to the environment or additional consumers in the system, such as pumps, control systems, etc. Therefore, more energy is required for charging than is available for discharging, and the charging costs are corrected by a factor of $1/RTE$.

- CO_2 pricing CO_{2f} [EUR/kWh]: A profit may be generated if the use of the storage facility reduces CO_2 emissions. An example of this is a thermal energy storage system charged via waste heat. If the heat from the storage system is used, for example, to heat industrial processes that would otherwise be heated by gas combustion, the CO_2 pricing of the industrial process can be reduced based on the CO_2 emissions saved. In practice, this requires knowledge of the CO_2 price [€/t] and the CO_2 emission factor [t/kWh] of the reference energy.

The equation used for the acceptable storage capacity cost SCC_{acc} is:

$$SCC_{acc} = \frac{(REC - OMC - \frac{CHC}{RTE} + CO_{2f})}{ANF} \cdot N_{cycle} \quad (7-7)$$

For the realised storage capacity cost SCC_{real} is:

$$SCC_{real} = \frac{INC - CAP}{SC} \quad (7-8)$$

- CAP [EUR] refers to savings in capital costs achieved by installing the energy storage system – for example through a more cost-effective design of the surrounding energy system. If, for example, the storage system enables peak shaving, a local power generation facility can be scaled down, or a grid connection can have a lower capacity. Subsidies or grants received for the installation of the energy storage system can also be taken into account using the CAP parameter.

Fixed operating costs – for example, costs incurred for insurance or personnel that are independent of the amount of energy generated – are added to the investment costs (INC).

The feedback from companies on this approach was that it is helpful when adding energy storage to an existing system. The result generated using approach (2) can be interpreted as follows, for example: If the realised storage capacity costs are higher than the acceptable storage capacity costs, it is advisable to identify additional revenues that could potentially be generated with the energy storage system in question in the specific application. The following approach (3) is suitable for this purpose. If the realised storage capacity costs are within or below the acceptable range, it is advisable to conduct a more detailed analysis of economic efficiency, taking into account other relevant techno-economic parameters.

7.4.2.3 Revenue-oriented version

Approach (3) uses the same input parameters for the annuity calculation as the other two approaches. The main difference between them is that approach (3) takes into account various revenues that can be generated from the operation of the energy storage facility. Approach (3) is therefore particularly advantageous when considering different sources of income. Different sources of income must be taken into account, especially when the implementation of a storage system in an application can bring a number of advantages (and the resulting revenues).

The new parameters for calculating acceptable storage capacity costs are:

- Annual revenue per storage capacity REV_{SC} [EUR/kWh]: REV_{SC} is used to calculate the annual revenue generated from each kWh supplied by the energy storage facility. Example: Revenue from heat supplied by a heat storage facility to a district heating network.
- Revenue per cycle REV_C [EUR]: REV_C can be used if there is a specific revenue per cycle. This is the case, for example, when considering an energy storage technology that mainly supplies electricity but can also provide waste heat, and the yield per cycle for the waste heat is known. REV_C must be divided by the storage capacity SC in the calculation. REV_C is to be divided by the storage capacity SC .
- Variable operating costs OMC_{var} [EUR/kWh] correspond to OMC from approach (2).

The equation used in approach (3) for the acceptable storage capacity cost SCC_{acc} is:

$$SCC_{acc} = \frac{\left(REV_{SC} + \frac{REV_C}{SC} - OMC_{var} - \frac{CHC}{RTE} + CO2_f \right) \cdot N_{cycle}}{ANF} \quad (7-9)$$

The additional new parameters for calculating the realised storage capacity costs are:

- Fixed operating costs OMC_{fix} [EUR/a]: OMC_{fix} represents annual costs for insurance or personnel that are independent of energy consumption. These are added to the investment costs INC , taking into account the amortisation period n .
- Annual revenue REV_A [EUR/a]: REV_A allows annual revenues generated by the installation of the energy storage system to be taken into account. Example: Revenue from grid services such as frequency control reserve (FCR). REV_A is subtracted from the investment costs INC , taking into account the amortisation period n .

The equation used in approach (3) for the realised storage capacity cost SCC_{real} is:

$$SCC_{real} = \frac{INC - CAP + (OMC_{fix} - REV_A) \cdot n}{SC} \quad (7-10)$$

7.4.3 Excel tool

An Excel sheet has been elaborated to a tool, to allow users the simple application of the *maximum acceptable storage capacity cost* approach. Users have to fill in their storage and use case specific data, while the evaluation is given as a diagram (Figure 7-26). The upper part of Figure 7-26 shows the list of parameters that are the basis of the model. Yellow marked fields have to be filled by the user, green marked values are calculated. As a result (lower part) the user gets a diagram showing the lines representing the acceptable storage capacity costs. As some parameters can be given as range with a minimum and maximum assumption, the acceptable storage capacity results on two lines: red representing the higher acceptable costs and blue the low ones. The green rectangle gives the realised storage capacity costs and the range of realizable cycles per year.

Enter value

Calculated value

Top-down: The market

$$ANF = \frac{(1+i)^n \cdot i}{(1+i)^n - 1}$$

$$SCC_{acc} = \frac{REC}{ANF} \cdot N_{cycle}$$

Variable	min/max	Unit	Value
Interest Rate i	min.	-	5%
	max.	-	10%
Payback Period n	min.	a	8
	max.	a	15
Annuity Factor ANF	min.	1/a	0,096
	max.	1/a	0,187
Reference Energy Costs REC	min.	€/kWh	0,03
	max.	€/kWh	0,09
Number of Cycles per Year N_{cycle}	min.	1/a	150
	max.	1/a	250
Acceptable Storage Capacity Costs SCC_{acc}			

Bottom-up: Your energy storage system

$$SCC_{real} = \frac{INC}{SC}$$

Variable	min/max	Unit	Value
Investment costs INC	min.	€	65.000
	max.	€	100.000
Storage Capacity SC	min.	kWh	300
	max.	kWh	800
Realized Storage Capacity Costs SCC_{real}	min.	€/kWh	81,25
	max.	€/kWh	333,33
Number of Cycles per Year N_{cycle}	min.	1/a	150
	max.	1/a	250

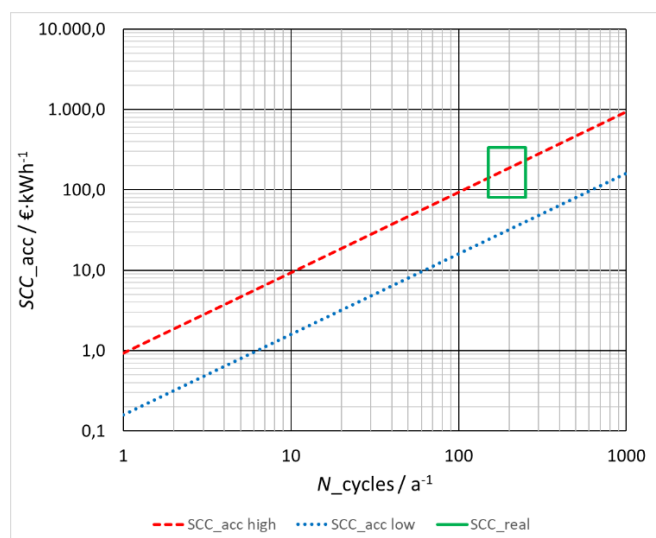


Figure 7-26: Screenshot of the Excel tool for the maximum acceptable energy storage cost approach.

Since some parameters can be specified as a range with a minimum and maximum value, the acceptable storage capacity is determined by two lines: red represents the higher acceptable costs and blue represents the lower costs. The green rectangle indicates the realised storage capacity costs and the range of feasible cycles per year. Here, too, ranges can be specified for the input parameters.

The developed Excel tool is provided as an open source file on the Task 41 page on the ES TCP website. This chapter of the final report serves as handbook to use the tool.

7.4.4 Conclusions

A simple methodology has been developed for the economic evaluation of energy storage systems for a specific user type and a specific application. The economic evaluation is based on the assumption that the cost of energy from the storage system must not exceed the cost of an alternative energy supply.

The methodology highlights important findings on the economic efficiency of energy storage systems. Firstly, the maximum acceptable storage costs for a fixed storage period depend on the economic environment of the user (e.g. industry or buildings) due to differences in the payback period, the discount rate and the costs of the reference energy from the market. Secondly, the annual number of storage cycles has by far the greatest influence on the maximum acceptable storage capacity costs and the cost efficiency of storage systems. If the annual number of storage cycles is sufficiently high, many energy storage technologies can become economically competitive. Thirdly, there are scenarios in which most storage technologies are economical. In this case, the systems should be compared in terms of their physical and technical properties.

The methodology was developed in collaboration with companies. Three different approaches are available. Two of the approaches are particularly suitable when the main purpose of the energy storage system is to supply a certain amount of energy and thus reduce the use of alternative energy sources. The third approach is advantageous when considering different sources of income, i.e. when the implementation of a storage system in an application brings several advantages and resulting revenues.

An Excel tool has been developed to apply the three approaches and is published on the ES TCP homepage.

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8 12-Step Approach for Business Model Development

In this final chapter, a 12-step approach allows various target groups to assess whether energy storage is appropriate, adds value to the system, define its services, choose the right strategy and technology, and build more robust and sustainable business models for the value chain.

8.1 Introduction

A framework to translate an energy-storage problem or opportunity into a viable business case was developed. Its goal is to clarify how storage creates value and how this value can be systematically incorporated into project development.

To support this work, the study first compiled a list of storage value propositions and then developed a 12-step evaluation framework. The study covers electrical, thermal, and chemical storage across both centralised and decentralised systems, including electricity, heating and cooling, mobility, and industrial applications. The framework is intended for policymakers, grid operators, companies, and individuals considering storage solutions.

Partially inspired by the energy storage valuation frameworks developed in this Task, a study also was developed and published by the Clean Energy Ministerial Supercharging Battery Storage initiative on the value of electricity storage globally, exhibiting 25 case studies that show how value can be created for society and monetised in energy storage projects. A summary of this study is presented in the Exhibit at the end of this chapter.

8.2 Literature review/ State of the Art

A review of existing frameworks showed that structured approaches exist for electrical storage by IRENA [94], which was also the starting point of the benefit-revenue-cost approach in chapter 6 (see Figure 6-1), and for thermal storage [95]. However, no comparable framework was found for chemical storage, motivating the development of a unified 12-step approach drawing from both IRENA and HEATSTORE.

In this study, “services” refers to the applications or value propositions of storage. Existing literature was used to compile service lists for electricity, thermal, and chemical storage. The European Association for Storage of Energy (EASE) provides a comprehensive list for electricity; HEATSTORE covers thermal services but mainly for UTES; and no full list existed for chemical storage. Hydrogen was therefore used as the starting point due to its growing role in Europe’s energy transition strategy.

A key element across all sources is value stacking—combining multiple direct and indirect services to increase total value. Value stacking is often essential for making a storage project financially viable or more attractive compared to relying on a single service.

8.2.1 Electricity storage valuation framework

IRENA proposes a five phase Electricity Storage Valuation Framework (ESVF) [96] to support the integration of variable renewable energy (VRE)—notably solar and wind—into power systems. The

framework is designed to quantify the system value of electricity storage, guide technology and service selection, and assess project viability relative to alternative sources of flexibility. It explicitly addresses key hurdles to largescale storage deployment: the difficulty for asset owners to monetise the value they create for the wider system.

The five steps at a glance:

1. Identify services that storage can deliver to enable Variable Renewable Energy integration.
2. Map technologies to services, establishing which storage options can technically and economically provide those services.
3. Analyse system value of storage versus alternatives (demand response, stronger transmission, and flexible generation).
4. Simulate project operation and stack revenues across eligible markets/services.
5. Assess project viability by comparing system value with monetisable revenues under the prevailing market design to reveal potential “missing money” gaps and policy needs.

8.2.2 Business model framework for Underground Thermal Energy Storage

Heating and cooling constitute nearly half of Europe’s final energy consumption, much of which is still supplied by fossil fuels. The HEATSTORE project [95] targets the advancement of high temperature Underground Thermal Energy Storage (HTUTES) technologies—typically ranging from 25 to 90 °C—to enable decarbonised heat supply. Its objectives include lowering technological costs, reducing development risks, improving thermal performance, and accelerating market uptake. Work Package 6 (WP6) focuses on developing and validating business models that integrate distributed energy resources, UTES systems, and optimised multi-energy networks.

Key Components of the HEATSTORE Business Model Framework:

1. Characterise the UTES network context: define temperatures, sources, demand profiles, system layout, and UTES type to set technical boundaries and integration requirements.
2. Identify key services, activities, and resources: determine the value UTES provides (e.g., peak shaving, seasonal storage, avoiding curtailment, relieving heat-pump congestion, improving supply security).
3. Define actors and roles: map system owners, district-heating operators, regulators, municipalities, industry, and investors, including governance and interaction structures.
4. Formulate business models per actor: outline costs, revenues, partnerships, and contractual arrangements for each stakeholder to align incentives.
5. Identify barriers and risks: assess regulatory, technical, market, and societal obstacles and define mitigation needs or policy interventions.

8.2.3 Storage services

Both the IRENA and HEATSTORE frameworks start by listing the services offered by storage. Building on this, the literature review consolidates service inventories across electricity, thermal/UTES and

chemical storage with a focus on hydrogen. The aim is to enable value stacking and business model design across sectors.

8.2.3.1 Electricity Storage services

EASE [97] categorises electricity storage applications into five groups:

- Generation support & bulk storage: enable largescale renewable integration and energy shifting.
- Services to support transmission infrastructure: alternatives or complements to grid reinforcements.
- Services to support distribution infrastructure: defer upgrades and improve local reliability.
- Ancillary services: frequency control and other system operation services tendered by Transmission System Operator (TSO) and Distribution System Operator (DSO)
- Customer energy management (behind-the-meter): manage costs and increase self-consumption for residential, commercial, and industrial users.

8.2.3.2 Thermal energy storage services

The following list of services are offered by underground TES as observed by the HEATSTORE project.

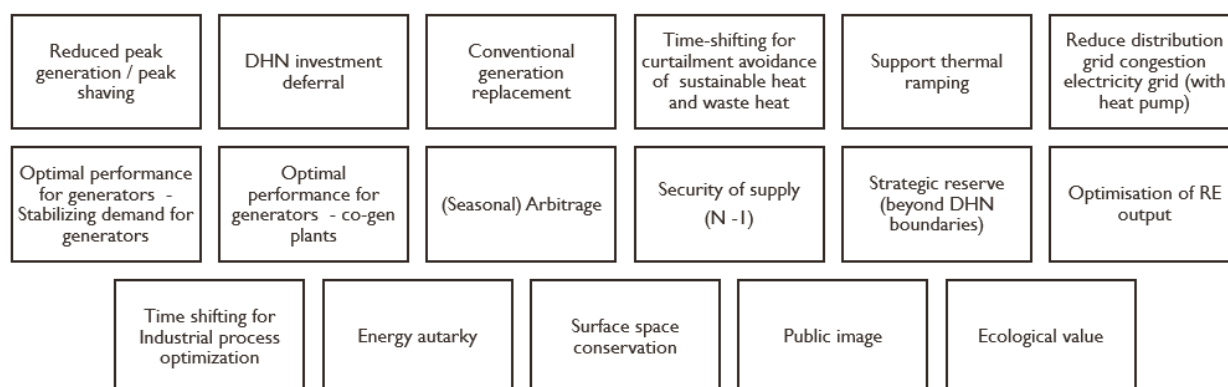


Figure 8-1: Applications of underground TES.

Thermal Energy Storage supports multiple markets and policy goals as well (EASE 2023 [98]):

- Electricity market: renewable energy sources (RES) integration, grid scale flexibility, ancillary services (like arbitrage, frequency services, load following, etc.).
- Heating & cooling market: decarbonising industrial processes, heating and cooling.
- Combined heat and- power synergies: coupling combined heat and power (CHP) and TES to co-optimize heat and power assets and revenues.
- Repurposing fossil assets: convert existing infrastructure into low-carbon flexibility hubs.
- Energy efficiency: reduce wasted heat and cut carbon costs.

8.2.3.3 Hydrogen storage services

Hydrogen storage delivers substantial system-level value by enhancing security of supply, enabling flexibility from real-time balancing to seasonal shifting, and supporting the cost-efficient evolution of

electricity, hydrogen, and natural-gas networks. Its ability to store energy at large scale and for long durations makes it a crucial buffer that stabilises systems with growing shares of variable renewable energy. The Energy Transition Expertise Centre (ENTEC) [99] highlights that this system-level flexibility reduces curtailment, mitigates price volatility, and supports optimal deployment of infrastructure across multiple energy carriers.

Beyond overarching system benefits, hydrogen storage creates actor-specific value throughout the energy chain. Renewable-electricity producers benefit from reduced curtailment and less exposure to price risk, while hydrogen producers and importers gain optimisation advantages in electrolyser sizing, import strategies, and market hedging. Demand-side sectors improve supply security and portfolio flexibility; TSOs and shippers rely on storage for balancing and network optimisation; and storage operators capture revenue from seasonal arbitrage and capacity services. Society additionally benefits from insurance value through improved resilience to extreme events, protection against international supply disruptions, and greater market-price stability. Artelys & GIE [100] further reinforce these insurance and system values, and add environmental value by limiting fossil-based hydrogen production, avoiding renewable-energy curtailment, and reducing fossil-based electricity dispatch.

Subsurface and underground hydrogen storage (UHS) play a particularly strategic role. The Nederlandse Aardolie Maatschappij (NAM) identifies key use cases such as market-oriented storage operation, storage-as-a-service models, and system-stability functions including black-start capability and strategic reserves. Guidehouse [101] categorises the benefits of UHS into market value (arbitrage and price-spread reduction), system value (reduced peak-capacity requirements and avoided grid investment), and insurance value (resilience under extreme conditions). Artelys & GIE add the concept of kick-start value, where underground storage enables optimal investment sizing in renewable capacity to meet transition targets. Together, ENTEC, NAM, Guidehouse, and Artelys & GIE demonstrate that underground hydrogen storage is a foundational flexibility and resilience asset serving markets, infrastructure operators, industrial consumers, and society at large.

The activities under the EcoEneSto Task have synthesised above mentioned international studies and recognises that hydrogen storage creates value directly (using stored hydrogen), indirectly (when converted to electricity, heat, or feedstock), and societally (system and resilience benefits). It provides the basis for business-case development for chemical energy storage within the broader 12-step energy storage valuation framework.

- **Direct Services:** Using stored hydrogen itself enables optimised production and import strategies, better electrolyser sizing, long-term contracting, and price-risk reduction. TSOs and shippers gain balancing, congestion relief, and infrastructure optimisation. Storage operators benefit from arbitrage and capacity-market revenues, while demand sectors improve supply security, stability, and risk hedging.
- **Indirect Services:** When converted, stored hydrogen provides flexible low-carbon power generation, peak-demand support, and grid-investment deferral; supports heat-system flexibility and sector coupling; and enables continuous, low-carbon industrial operation and feedstock supply.
- **Societal & System-Level Services:** Hydrogen storage enhances resilience to extreme events, reduces geopolitical and supply-chain exposure, and stabilises market prices. Underground

storage improves spatial efficiency, renewable producers benefit from reduced curtailment and price volatility, and non-hydrogen consumers gain improved security of supply and decarbonisation options.

8.2.3.4 Industrial Energy Storage Services

Sandia National Laboratories' survey [102] of energy-intensive industrial sectors (chemicals, minerals, transport, iron & steel, and cement) highlights the broad role that energy storage can play in enabling industrial decarbonisation. Companies reported that storage is essential for both direct and indirect electrification, helping facilities integrate more renewable electricity into operations. Thermal storage—including process-heat and waste-heat storage—was identified as a major opportunity to improve efficiency and cut fuel use, while chemical production using stored molecular carriers provides another pathway to convert surplus or waste heat into valuable industrial inputs. [102]

The study also emphasises the role of hydrogen storage, both as a fuel and as a reactant in industrial processes, supporting flexible, and low-carbon operation. Finally, facilities see storage to enhance resilience, with backup heat and backup electricity improving reliability and reducing downtime.

8.3 Results: the 12-step Energy Storage Valuation Framework

The IRENA framework clearly distinguishes monetisable and non-monetisable storage benefits and compares them against project costs and revenues, but it does not address how to build business models or identify non-essential services that could add project value. The HEATSTORE framework, in contrast, provides detailed guidance on business-model design but offers limited support on technology selection, service definition, and sizing—areas in which IRENA is stronger.

This study therefore combines both frameworks and more studies into a new, integrated energy-storage evaluation approach. The literature review highlighted the importance of value stacking and revealed a gap in chemical energy storage service inventories; hydrogen storage was selected to begin filling this gap due to its expected role in the EU energy transition.

The resulting 12-step framework helps project developers but also policy makers and NGOs assess whether energy storage is appropriate, adds value to the system, define its services, choose the right strategy and technology, and build more robust and sustainable business models for the value chain. A summary of the 12-step approach is provided below.

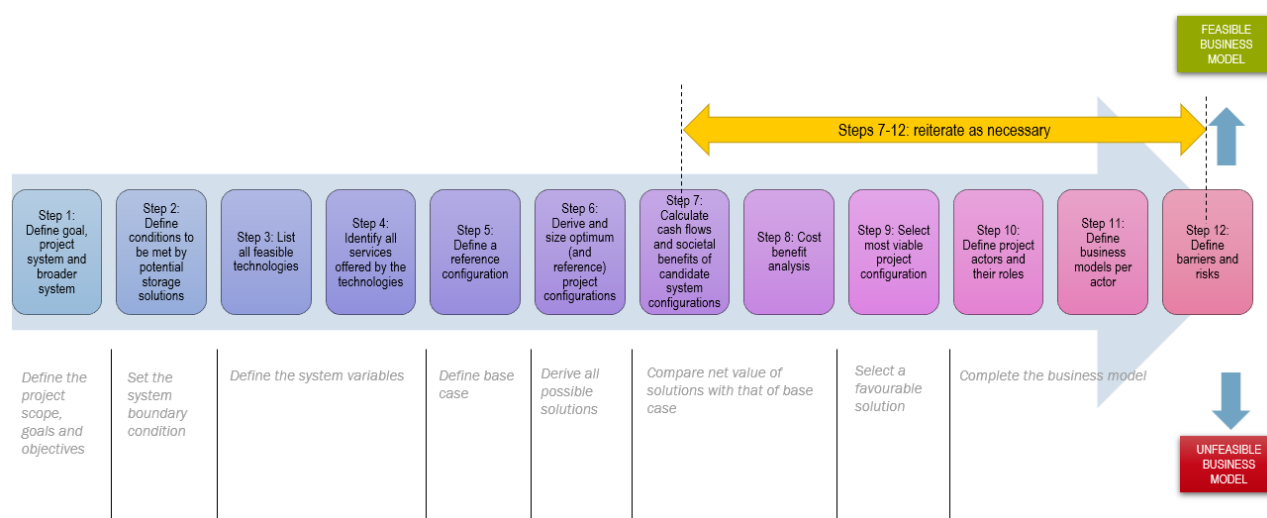


Figure 8-2: Value Creation and Business model framework.

8.3.1 Steps 1–6: System Definition & Technical Design

Step 1 defines the project system, objectives, stakeholders, KPIs, and project environment. Step 2 sets technical, economic, societal, environmental, legal, and safety boundary conditions using a PESTEL-based⁶ approach. Step 3 lists feasible technologies. Step 4 maps services to technologies to identify value-stacking opportunities. Step 5 develops the reference configuration, including a situation without energy storage. Step 6 derives and sizes candidate configurations using capacity-expansion and production-cost modelling.

8.3.2 Steps 7–12: Economic Evaluation, Actors & Business Model Development

Step 7 quantifies financial cash flows and societal benefits for all scenarios. Step 8 performs cost-benefit analysis using financial and economic indicators. Step 9 selects the most viable configuration aligned with objectives defined in Step 1. Step 10 defines all project actors, roles, and market structures. Step 11 develops business models per actor, including financing, cost structures, revenue models, partnerships, contracts, and risk-sharing. Step 12 identifies regulatory, technical, market, societal, and environmental risks and the associated mitigation measures. At the end of the execution of any of the steps from 7 to 12, the analysis might prove the solution selected to be infeasible. When that happens, it is advised to repeat the fault-determining step or reiterate the steps leading up to it between, steps 7 and 12, by altering parameters/strategies that rectify the fault identified.

⁶ A strategic framework for analyzing the political, economic, social, technological, environmental, and legal (PESTEL) factors to identify opportunities and threats in an organisation.

8.3.3 Example Application of the Energy Storage Value Creation & Business Model Framework

This write-up presents an example of how the energy storage value creation and business model framework can be applied in a real-world context. It is based on work performed for Rijkswaterstaat (RWS), the executive agency of the Dutch Ministry of Infrastructure and Water Management. The example demonstrates how the framework systematically guides the assessment of energy storage options in road tunnels, accounting for both technological and economic considerations, while maintaining a clear link to societal value creation.

8.3.3.1 Context and Problem Definition

RWS has set the ambitious goal of becoming climate neutral by 2030 and seeks to contribute positively to the broader Dutch energy transition. One promising opportunity lies in the use of energy storage systems in road tunnels, which may reduce grid congestion and improve the resilience and autonomy of tunnel operations. However, existing analyses of energy storage are too generic to address the highly specific characteristics of tunnel energy systems, which include:

- A primary grid connection for normal operation
- A uninterrupted power supply (UPS) system providing one hour of backup power
- Secondary energy supplies (e.g., generators or secondary grid connections) for prolonged outages

Tunnel electricity consumption is low under normal operation but can increase sharply during incidents, leading to oversized grid connections. Because storage already plays a role in UPS systems, it is natural to explore expanded uses of storage in both primary and secondary energy supply. RWS commissioned TNO to analyse these possibilities.

8.3.3.2 Applying the Framework Step-by-Step

The example follows the 12-step value creation and business model framework. The methodology ensures that technical feasibility, system impacts, societal benefits and business models are all considered coherently.

STEP 1 – DEFINE GOAL, PROJECT SYSTEM AND BROADER SYSTEM

- Project system: Road tunnels under RWS management.
- Broader system: The surrounding neighbourhood energy system, the Dutch local grid and national energy system.

The analysis aims to understand how storage can reduce tunnel energy consumption, increase self-sufficiency, support the electricity grid and create societal value.

STEP 2 – DEFINE CONDITIONS FOR STORAGE SOLUTIONS

Boundary conditions were established to ensure practical and safe implementation:

- Commercial availability
- Safety compliance
- Power/energy scale: minutes–hours discharge, kWh–MWh storage
- Acceptable round-trip efficiency
- Minimal spatial footprint
- Low emissions

STEP 3 – IDENTIFY FEASIBLE TECHNOLOGIES

A broad set of commercially available storage and relevant non-storage technologies was considered that meets the conditioned identified in step 2:

- Vanadium redox flow
- Lithium-ion (small and large scale)
- Sodium–sulphur
- Sodium–nickel chloride
- Lead–acid
- Nickel–metal hydride
- Diabatic compressed air storage
- Solar PV (non-storage, but relevant for energy neutrality)

STEP 4 – IDENTIFY REQUIRED SERVICES

The following services were determined as relevant for achieving RWS goals:

- Emergency power
- Energy-neutral tunnel operation
- Imbalance services
- Peak levelling
- Grid congestion management

STEP 5 – DEFINE A REFERENCE CONFIGURATION

The reference is a Do-Nothing scenario, representing business-as-usual tunnel operation with no storage or renewable generation. Comparing all variants against this baseline allows assessment of incremental technical and economic benefits.

STEP 6 – DERIVE OPTIMUM CONFIGURATIONS

The choice of technology depends on the specific details of a tunnel (how far in the future will the investment take place; is there space next to the tunnel or only inside it; is a proven solution desired

or is a more experimental application of new technology also possible; etc.). For cost calculations, a generic battery with the characteristics of a Li-ion battery is assumed.

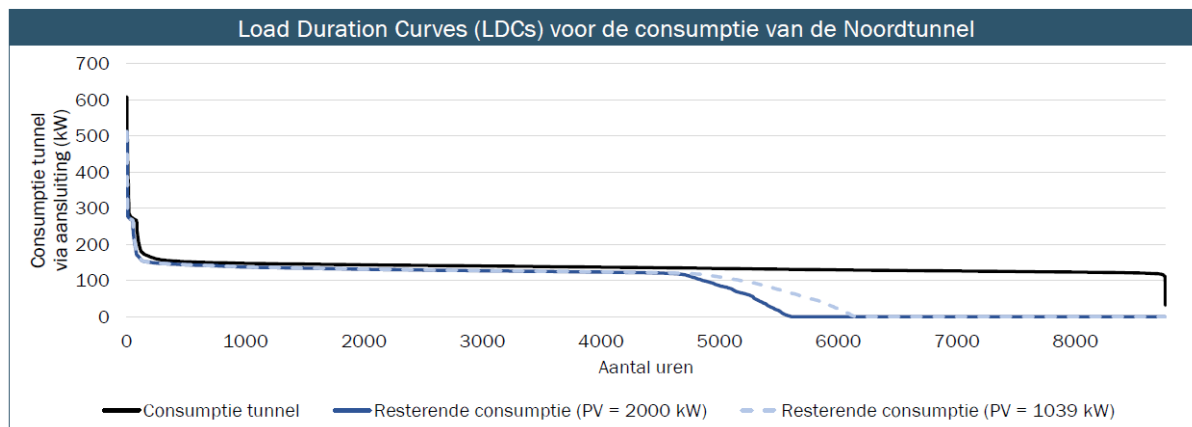


Figure 8-3: Load Duration Curves for the consumption of the North Tunnel (source: [103])

Two battery configurations were shortlisted:

- Low-Energy Tunnel (focus on self-sufficiency)
- Day-Ahead Controlled Tunnel (adding an energy market service)

Sizing Solar PV

Analysis showed that:

- 1,039 kW of PV yields ~39% reduction in grid consumption.
- Increasing to 2,000 kW increases this only marginally (to 43%), due to curtailment.

Thus, 1,039 kW PV was selected.

Low-Energy Tunnel

Sizing the Battery:

For a low-energy tunnel, self-sufficiency increases with storage capacity but exhibits diminishing returns (As can be seen in Figure 8-4). A lithium-ion battery sized at

- 340 kW charge/discharge power
- 6 hours of storage (2,040 kWh)

reaches 72% self-sufficiency, close to the maximum feasible level ($\approx 74\%$).

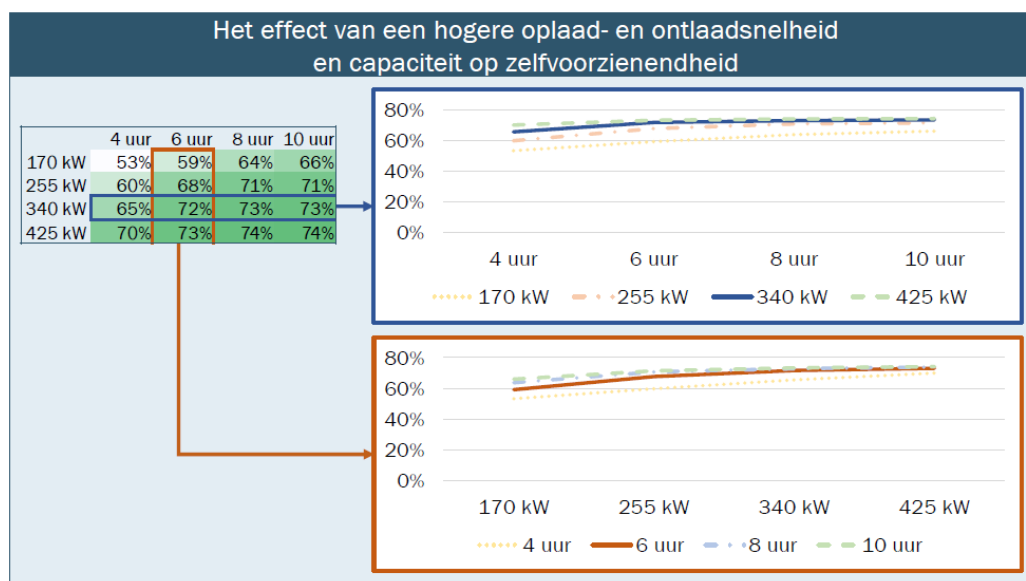


Figure 8-4: Impact of battery choice on self-sufficiency (source: [103])

Day-Ahead Control Variant

The day-ahead control is a service added on top of the low-energy tunnel configuration. A dispatch model was used to simulate market-driven charging and discharging. The battery buys electricity when prices are low and sells (or avoids use) when prices are high. Standardised 2021 price profiles were used to ensure representative outcomes.

STEP 7 – CASH FLOW AND SOCIETAL BENEFIT CALCULATION

A financial assessment was performed for:

1. Business as Usual
2. Low-Energy Tunnel
3. Day-Ahead Control

Assumptions

- CAPEX + OPEX based on lithium-ion and PV technologies
- Net present value (NPV) over 15 years
- Weighted average cost of capital = 4%
- Day-ahead prices from 2021 for market revenues

Table 8-1. Results of financial analysis (source: [103])

KPI	Business as Usual	Low-energy Tunnel	Day-ahead
CAPEX Storage	-	-€ 821,000	
CAPEX Solar PV	-	-€ 561,000	
OPEX Storage (€/yr.)	-	-€ 2,000	
OPEX Solar PV (€/yr.)	-	-€ 5,000	
Energy Trading (€/yr.)	-€ 123,634	-€ 28,200	+€ 11,000
NPV	-10 M€	-19 M€	-16 M€

It can be seen from Table 8-1 that both storage-based configurations reduced operating energy costs, though not enough to repay total investments under current price conditions.

STEP 8 – COST–BENEFIT EVALUATION

Table 8-2. Comparison of battery configurations (source: [103])

KPI	Low-energy Tunnel	Day-ahead
Self-sufficient	72%	47%
Contribution to market incentive (% of year)	27%	37%
Opposition to market incentive (% of year)	21%	0%
Net Present Value vs Business as Usual	-9 M€	-6 M€
Autonomy (avg. hours autonomous operation above UPS system)	0 (winter) – 9 (summer)	4 (summer) – 8 (winter)
Space - Solar panels (m ²)	5,700	5,700
Space - Battery (m ²)	160	160

Key performance indicators (KPIs)

1. Degree of self-sufficiency = $100\% - \frac{\text{consumption via grid connection}}{\text{total consumption}}$
2. Alignment with market incentives--this analysis uses the price incentive from the day-ahead market as a starting point to determine whether the tunnel's battery can contribute to the energy system. High prices (market price electricity > electricity discharge costs storage) create an energy shortage, while low prices (market price < electricity charging costs of storage) create a surplus in the energy system. This dynamic, through electricity prices, acts as an incentive for storage.
3. Financial value (NPV)
4. Tunnel autonomy (average number of daily hours of autonomous operation on top of UPS system)
5. Space requirement

Findings

- Low-energy tunnel: ~72% self-sufficiency; battery supports the grid 27% of the year but opposes it 21%.⁷
- Day-ahead tunnel: lower self-sufficiency (~47%), but contributes to the energy system for 37% hours of the year.
- Day-ahead control yields better financial performance.
- Both control mechanisms can increase a tunnel's autonomy in summer, as the battery can temporarily meet the tunnel's demand in the event of a grid failure. Day-ahead control can also do this in winter.
- Spatial needs are dominated by PV area (~5,700 m² vs. 160 m² for the battery).

The study highlights that stacking services improves storage value and is likely essential for viable project configurations.

STEP 9-12 – SELECTION OF MOST VIABLE OPTION AND IDENTIFY RELEVANT ACTORS, BUSINESS MODELS, BARRIERS

This step was outside the project scope, but the insights provided allow RWS to make informed strategic decisions.

8.4 Conclusions

A key contribution of this approach to the overall Task results is the explicit linkage between technical services, economic value, and paying actors. By systematically identifying who benefits from specific storage services and how these benefits can be monetised, the framework helps bridge the gap between system-level value and project-level business cases.

The framework is technology-neutral and applicable across energy sectors, including electricity, heating and cooling, hydrogen, and industrial applications. It explicitly incorporates uncertainty, regulatory constraints, and the potential for revenue stacking, reflecting the complexity of real-world deployment conditions.

The 12-Step approach demonstrates that successful energy storage deployment requires more than favourable technology costs. Viable business models emerge only when technical design, economic evaluation, and institutional context are aligned. The framework therefore serves as a practical guide for policymakers, system planners, and project developers aiming to translate the benefits of energy storage into bankable projects.

⁷ When electricity prices are high, the system is interpreted as relatively short of electricity. In that situation, the battery supports the grid if it discharges, because it adds electricity when supply is scarce.

When electricity prices are low, the system is interpreted as having surplus electricity. In that situation, the battery supports the grid if it charges, because it absorbs electricity when there is excess supply.

The battery opposes the grid when it does the reverse: for example, charging during high-price periods or discharging during low-price periods. That behavior increases demand when electricity is scarce or adds supply when electricity is already abundant.

8.5 Whitepaper on Exploring the Value of Electricity Storage

The work within the Task and especially the Subtask Leader Joris Koornneef contributed to the whitepaper EXPLORING THE VALUE OF ELECTRICITY STORAGE: A COMPREHENSIVE INTERNATIONAL OVERVIEW which is outlined on the following page.

Whitepaper on Exploring the Value of Electricity Storage

Through the Clean Energy Ministerial (CEM), countries collaborate to accelerate policies and technologies that support decarbonisation. At COP28 in 2023, CEM launched the Supercharging Battery Storage (SBS) initiative to advance battery storage on a global scale and meet the 2050 net-zero goal. At COP29, global organisations endorsed the Global Energy Storage and Grids Pledge, committing to deploy 1500 GW of storage in the power sector by 2030, representing a six-fold increase compared to 2023. This ambition reflects the need for flexible, reliable solutions capable of integrating large shares of renewable energy.

In 2025, the CEM SBS initiative launched a whitepaper that describes the technical and economic advantages that electricity storage can provide. Electricity storage brings wide-ranging benefits for modern energy systems. It improves system efficiency by shifting electricity from low-demand to high-demand periods, reducing curtailment of renewable generation and helping stabilise prices. Storage supports renewable integration by addressing intermittency and maintaining grid stability. It can also provide key ancillary services, including frequency regulation, voltage control, and spinning reserve. By reducing congestion or avoiding costly transmission and distribution investments, storage contributes to long-term affordability and overall system resilience.

Storage also delivers societal and environmental value. It enhances energy independence by reducing reliance on imported fuels, particularly in remote or island areas. It increases resilience by providing backup power during emergencies and improves energy access for communities, contributing to equity and energy sovereignty. Environmentally, storage enables higher renewable-energy shares and thereby reducing CO₂ emissions and improves air quality.

To ensure a stable and flexible energy supply and increase the value, a diverse portfolio of storage technologies is needed. Short-duration technologies such as lithium-ion batteries and supercapacitors complement long-duration solutions including pumped hydro, compressed air, thermal storage, and underground hydrogen storage.

Despite its benefits, many storage services remain undervalued in current markets. Key contributions—such as avoided emissions, reliability improvements, and deferred infrastructure—are often not monetised, creating a gap between the project costs and revenue earned by the project developers. The whitepaper uses 25 international case studies to demonstrate these values that energy storage can provide, their challenges and the diverse roles storage can play.

To overcome identified gaps, firstly, the whitepaper recommends several policy, supply chain, and financing actions. In the short term, policymakers should enable equal market access, support revenue stacking, and integrate storage into long-term infrastructure planning. Secondly, a broad portfolio with diversified supply chains strengthens resilience and energy independence. A viable business case should be ensured, together with the bankability of storage projects. Support mechanisms should be extended to decrease project costs and monetise undervalued system benefits. Achieving 1500 GW by 2030 will require coordinated global action, with electricity storage positioned as a foundation of a reliable and decarbonised energy future.

Link to report: <https://www.cleanenergyministerial.org/content/uploads/2025/08/cem-sbs-exploring-the-value-of-electricity-storage-a-comprehensive-international-overview.pdf>

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