Liquid air energy storage (LAES)

Vecchi, Andrea; Li, Yongliang; Ding, Yulong; Mancarella, Pierluigi; Sciacovelli, Adriano

DOI:
10.1016/j.adapen.2021.100047

Advances in Applied Energy 3 (2021) 100047

Contents lists available at ScienceDirect

Advances in Applied Energy

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

Liquid air energy storage (LAES): A review on technology state-of-the-art, integration pathways and future perspectives

Andrea Vecchi[a,*], Yongliang Li[a], Yulong Ding[a], Pierluigi Mancarella[b,c], Adriano Sciacovelli[a,*]

[a] Birmingham Centre for Energy Storage, School of Chemical Engineering, University of Birmingham, Birmingham B15 2TT, UK
[b] Department of Electrical and Electronic Engineering, The University of Melbourne, Parkville, Victoria 3010, Australia
[c] School of Electrical and Electronic Engineering, University of Manchester, Manchester M13 9PL, UK

A R T I C L E I N F O

Keywords:
Liquid air energy storage
Thermo-mechanical energy storage
Thermal energy storage
Cryogenics
Energy system integration
Decarbonisation

A B S T R A C T

Energy system decarbonisation pathways rely, to a considerable extent, on electricity storage to mitigate the volatility of renewables and ensure high levels of flexibility to future power grids. In this context, liquid air energy storage (LAES) has recently emerged as feasible solution to provide 10-100s MW power output and a storage capacity of GWhs. High energy density and ease of deployment are only two of the many favourable features of LAES, when compared to incumbent storage technologies, which are driving LAES transition from the concept proposed in 1977 to a real-life option. Two plants (350 kW and 5 MW) have been successfully built and demonstrated by Highview Power, and a 50 MW/250 MWh commercial plant is now under construction. Besides the commercial deployment, an ever-increasing body of literature on the topic proves the academic interest on LAES. However, literature heterogeneity in terms of the investigated concepts and plant layouts, working methodologies and study scope currently complicates the interpretation of outcomes. Few literature surveys have attempted to rationalise this landscape, yet leaving some key areas such as LAES integration practically unaddressed. The present article aims at filling these gaps and providing a holistic review of the LAES development. Uniquely in this review: i) we propose a new methodology for cross comparing the results from the literature and use it to harmonise techno-economic findings, ii) we review works where LAES operation in the energy system is considered and iii) we highlight promising LAES integration pathways and future research directions. More than 120 references on LAES have been processed according to the methodology. The results include once for all the state-of-the-art techno-economic performance of LAES, across all the concepts proposed, and propose necessary steps to further advance the LAES research. The need for more realistic LAES models for integration studies and a broader focus on LAES capabilities beyond electricity output, specifically for hybrid concepts, are highlighted.

1. Introduction

Under an unprecedented push towards carbon footprint reduction of the energy sector, renewable energy sources (RES) production has more than doubled between 2005 and 2017, reaching almost one third (29%) of all gross electricity generation in Europe, in 2016. Projections for 2050 show a RES penetration of some 70-85% of electricity worldwide, should global warming be contained within 1.5°C above pre-industrial levels [1]. Such a large penetration of RES must be supported by technologies that alleviate RES intrinsic volatility. Energy storage is one of such technologies, which is expected to grow in the United States, Europe, China and India with an estimated 310 GW of additional grid-connected facilities by 2050 [2]. Different storage technologies have emerged to support the energy system in different manners, from fast-response services to peak shaving, to long-duration storage of energy. In such a context, batteries have risen as potentially a competitive solution for the provision of fast power response services to short-duration storage up to ~4 hours. However, they remain unfavourable from economic standpoint for medium to long-duration storage. At the other end of the spectrum, pumped hydro storage provides large storage capacity and currently accounts for 94% of worldwide storage capacity [3], but further expansion is hindered by geographical restrictions. As a result, recent technological developments have focused on addressing the need for low-cost energy storage solutions capable to sustain energy discharge for tens of hours and with MWh- and even GWh-scale capacities, but without strict geographical limitations.

Among the proposed solutions, the so-called thermo-mechanical storage has emerged as a particularly attractive proposition to address such a need. This group of technologies exploits conversion processes between thermal and mechanical energy to store and retrieve electricity.

* Corresponding authors.
E-mail addresses: axv863@student.bham.ac.uk (A. Vecchi), a.sciacovelli@bham.ac.uk (A. Sciacovelli).

https://doi.org/10.1016/j.adapen.2021.100047
Received 15 June 2021; Accepted 15 June 2021
Available online 19 June 2021

Nomenclature

Symbols

LHV_f	Fuel lower heating value [kJ/kg]
T_0	Ambient temperature [K]
T_i	Temperature of LAES *i*-th thermal energy output [K]
T_j	Temperature of *j*-th thermal energy source [K]
T_k	Temperature of LAES *k*-th thermal energy sink [K]
m_f	Fuel mass flow rate [kg/s]
q_i^{LAES}	LAES *i*-th specific thermal energy output [kJ/kg]
q_j^{source}	Specific thermal energy from *j*-th source [kJ/kg]
q_k^{sink}	Specific thermal energy from *k*-th sink [kJ/kg]
w_{in}^{LAES}	LAES specific electricity input [kJ/kg]
w_{out}^{LAES}	LAES specific electricity output [kJ/kg]
η_E	Electrical efficiency [-]
η_{RT}	Roundtrip efficiency [-]
η_I	Energy (first-law) efficiency [-]fficiency (-)
η_{II}	Exergy (second-law) efficiency [-]
ξ_f	Fuel specific exergy [kJ/kg]

Acronyms

ASU	Air separation unit
CAES	Compressed air energy storage
CAPEX	Capital expenditure
EES	Electrical energy storage
LAES	Liquid air energy storage
LCOE	Levelised cost of electricity
LCOS	Levelised cost of storage
LNG	Liquefied natural gas
NPV	Net present value
ORC	Organic Rankine cycle
PBT	Payback time
PHES	Pumped hydro energy storage
PRU	Power recovery unit
PTES	Pumped thermal energy storage
RES	Renewable energy sources
TES	Thermal energy storage
TRL	Technology readiness level

They are typically characterised by 10-500 MW power output, sustain discharging over 2 and up to 12 hours (capacities between 10s MWh and GWh) and rely on well-established components, thus featuring low specific costs and potential for a fast deployment [4]. They can assist grid-level operation mainly through energy balancing, whilst also being capable of faster reserve services provision [5]. The main thermo-mechanical storage options and the respective technical specifications are listed in Table 1. This review article concerns liquid air energy storage (LAES), whose favourable features compared to incumbent solutions are further presented in section 1.1; the manuscript is organised as follows: the necessary background, the motivation and aim of this work are laid out in the remainder of the introduction. Section 2 describes the systematic methodology applied to literature collection and analysis, while sections 3 and 4 discuss the LAES concepts proposed so far, from a techno-economic perspective. Section 5 focuses on LAES integration with the energy system, and conclusions are finally drawn in section 6.

1.1. LAES process and history

Among thermo-mechanical storage, LAES is an emerging concept where electricity is stored in the form of liquid air (or nitrogen) at cryogenic temperatures [9]. A schematic of its operating principle is depicted in Figure 1, where three key sub-processes can be highlighted, namely charge, storage and discharge. During charge, ambient air is first purified, compressed using excess electricity and finally cooled down to reach the liquid phase; liquid air is then stored in near-atmospheric pressure vessels. Despite the cryogenic temperatures (liquefaction temperature for Nitrogen at ambient pressure is -196°C), vacuum or perlite insulation is very effective in limiting boiloff at this stage to only 0.1-0.07% per day [10]. When discharging, the required electricity is retrieved by pumping, evaporation and expansion of the liquid air stream through a set of turbines, in the power recovery unit (PRU). During the operation of LAES, hot and cold thermal streams are produced, respectively, during air compression (charge) and evaporation (discharge). As illustrated in Fig. 1, and discussed in greater detail later on in the review, such streams can be harnessed and reused within the process itself to improve plant energy efficiency. For this reason, the storage section of LAES typically comprises also thermal energy storage (TES) devices – a hot and a high-grade cold one – in addition to the liquid air tanks.

LAES is a thermo-mechanical storage solution currently near to market and ready to be deployed in real operational environments [12,13]. LAES exhibits significant advantages with respect to competing solutions: energy density is 1 to 2 orders of magnitude above the alternatives [11] and no site constraints limit its deployment. Because of the cryogenic temperatures of liquid air, the power generation cycle can be driven by largely available heat sources at ambient temperature. Not only this eliminates the need for combustion and associated carbon emissions, but it also allows the recovery of low-temperature streams such as waste heat within the LAES process. Integration with external sources of heat and/or cold enables energy synergies and symbiosis with

Table 1
Main thermo-mechanical storage technologies for grid-scale application and associated technical specifications [6–8].

	Pumped hydro energy storage (PHES)	Compressed air energy storage (CAES)	Pumped thermal energy storage (PTES)	Liquid air energy storage (LAES)
Power output	30 – 5000 MW	0.5 – 320 MW	10 – 150 MW	1 – 300 MW
Efficiency	70 – 87%	42 – 70%	48 – 75%	45 – 70%
Capacity	Up to 10s GWh	Up to GWh	Up to GWh	Up to 10s GWh
Energy density	0.5 – 2 Wh/L	0.5 – 20 Wh/L	10 – 100 Wh/L	50 – 200 Wh/L
Response time*	mins	mins	s - mins	mins
Lifetime	40 – 60 y	20 – 40 y	25 – 30 y	20 – 40 y
CO_2 emissions	No	Yes (CAES) / No (A-CAES)**	No	No
Installed capacity	168 GW	431 MW	N.A.	5 MW
Maturity	Mature	Early commercial	Developing	Developing/Demo
TRL level	9	5 (A-CAES) – 9	2 – 5	7 – 8
Site constraints	Yes	Yes***	No	No

* For CAES and LAES, response time below 1 minute has been demonstrated for operation in "Spin-Gen" mode: i.e. with turbine train synchronised to the generator and passively operated during storage idle periods.

** Adiabatic CAES (A-CAES) concepts reduce or avoid CO_2 emission from CAES, but they are not yet commercially mature.

*** Small systems (≤ 10 MW) present no site constraints when using above-ground storage vessels.

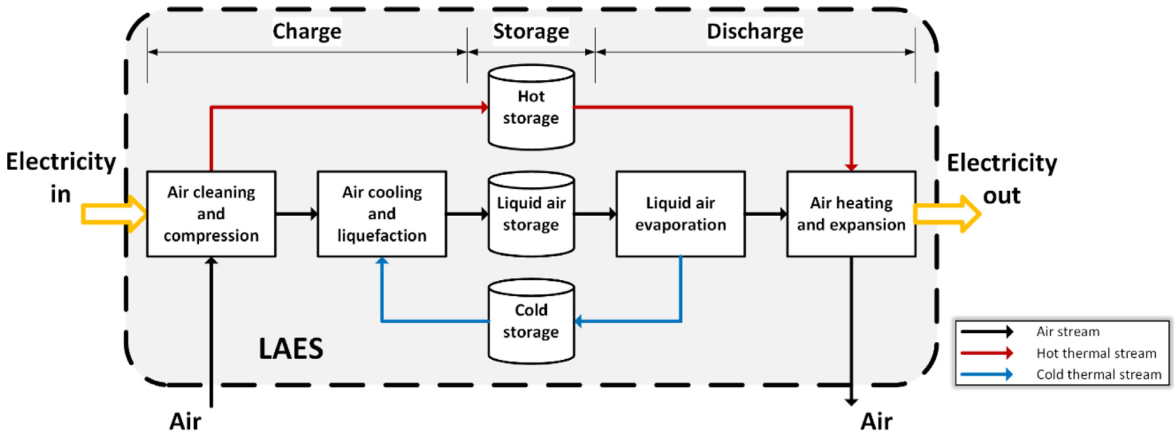

Fig. 1. Liquid air energy storage (LAES) process.

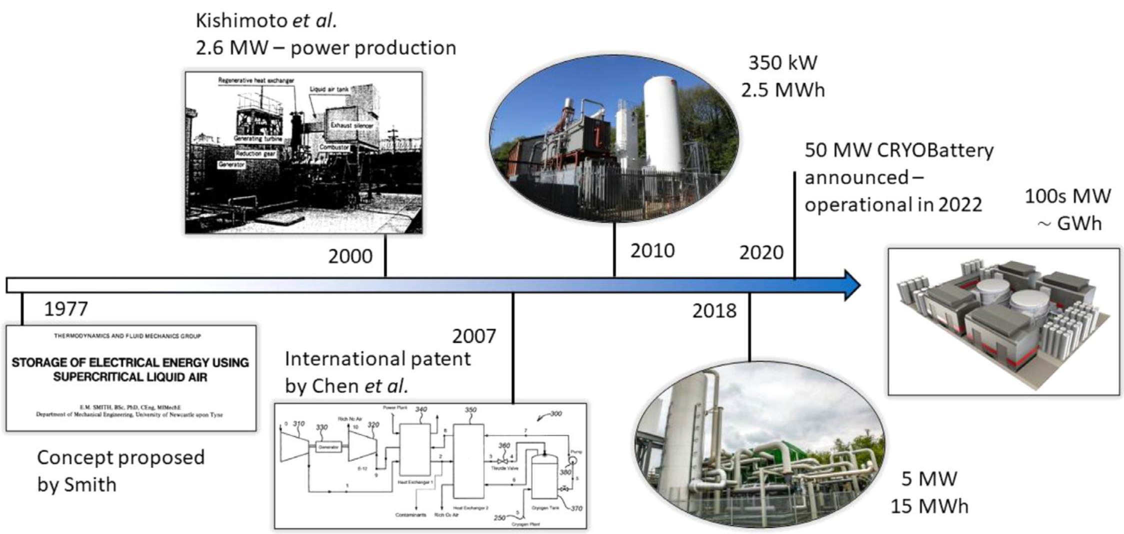

Fig. 2. Cornerstones in LAES development - timeline.

other processes, such as industrial sites near the location of LAES process. Underpinned by such compelling features and technical potential, endeavours towards the increase of LAES conversion efficiency – long been identified as a key drawback – and LAES commercialisation have achieved significant milestones in the latest years (see Fig. 2).

The concept of storing energy by means of liquid air was first proposed in 1977 [12], but experimentally investigated only several years later by Mitsubishi Heavy Industries and Hitachi. A 2.6 MW air-driven Rankine cycle was successfully operated by Kishimoto *et al.* [13] showing excellent stability characteristics for power generation, while researchers from Hitachi focussed on a layout including a gas combustor and a concrete regenerator to enhance gas liquefaction [14]. Efficiencies as high as 70% were predicted for the system [15]. Few years later, a joint venture between Highview Power and the University of Leeds, UK, led to the design and construction of the first fully integrated LAES plant in the world [16,17]. The 350 kW, 2.5 MWh pilot-scale plant was commissioned in 2010 and successfully tested in 2013, when it was relocated to the University of Birmingham for further research and development. This system established a cornerstone for LAES development, stimulating great research interest in the technology. A further 5 MW, 15 MWh pre-commercial plant by Highview Power was operated in June 2018 [18], leading to the deployment of two LAES 50 MW plants (named CRYOBattery) in the UK and US, recently unveiled from the same company [19]; these will be the first grid-connected LAES plants worldwide. Alongside commercial development, a number of international projects (e.g. the CryoHub project [20], and the IEA Energy Storage Task 36 [21]) have been established to further investigate, characterise and develop LAES technology.

1.2. Motivation and aim

Alongside the rapid transition of LAES from concept to a demonstrated storage technology, the interest in LAES has surged among the scientific community, especially in the last decade. Fig. 3 shows the growing number of relevant works in this field published each year. The largest portion (around 80%) of the available literature to date involves technical or economic assessments of LAES, with adopted methodologies varying greatly from parametric studies [22,23], component and plant-level optimisation [24,25], numerical and experimental analysis at plant and device scale [26]. Alongside investigations of standalone LAES process configuration, a significant number of works also investigated hybrid concepts involving the combination of LAES with external processes. Most recently (see Fig. 3), energy system integration studies have explored the operational value of LAES for services potentially extending from grid balancing, to waste heat/cold recovery in smart energy clusters [27], to a fully integrated “liquid air economy” [28].

Few attempts have been made to rationalise LAES literature over the years. A first survey was published in 2016 [29]; liquid air was presented with a focus on liquefaction and its application potential, but such study was inevitably limited by the scarce number of studies avail-

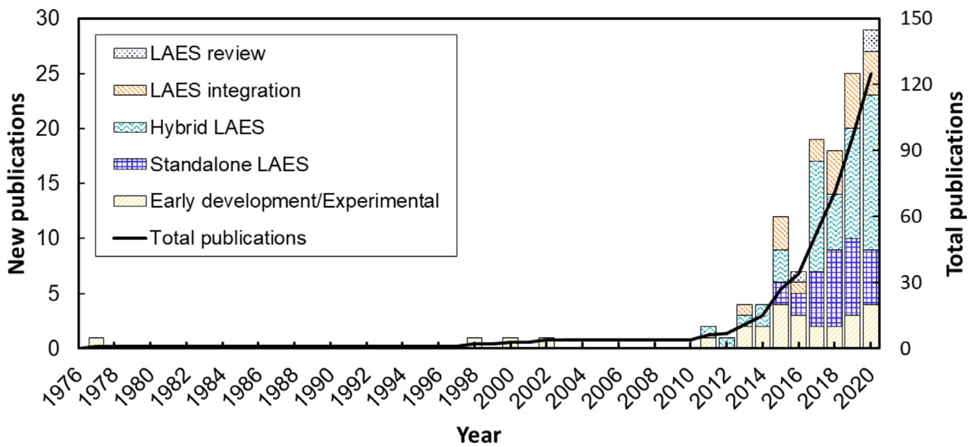

Fig. 3. Number of new relevant publications on LAES over time.

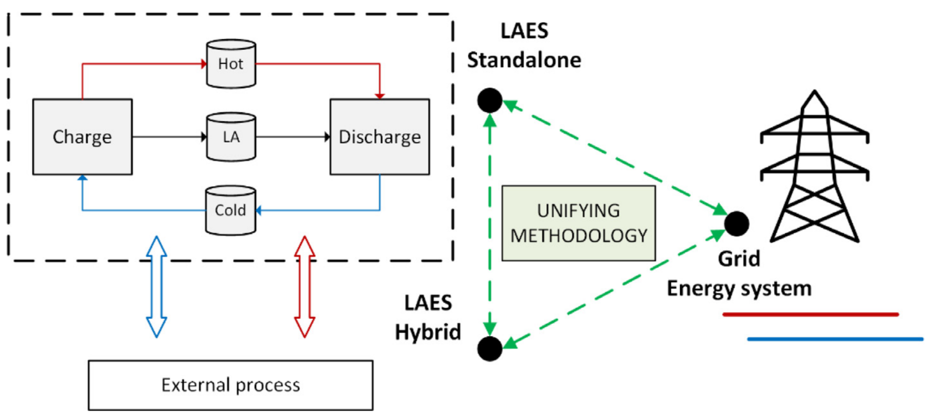

Fig. 4. Visual abstract for the present literature review document.

able at the time. Damak *et al.* [30] qualitatively reviewed LAES process principle and implementations, touching on hybridisation methods and future perspectives. Interestingly, they proposed a distinction between *"super-heating"* and *"combustion based"* power recovery process, suggesting different formulae may be suitable for efficiency calculation in each case. However, few hybrid layouts were considered and discussion of integration pathways for LAES mainly involved refrigerated warehouses. Recently, Borri *et al.* [31] used a bibliometric analysis to reveal the key research trends concerning LAES, clustering publications by authorship and keywords. A much larger number of thermodynamic studies as compared to economic assessments was highlighted, as well as a transition in the interest from the original LAES concept to LAES hybridisation with external processes.

At this stage, two are the knowledge gaps that a literature review should cover: 1) the absence of a unified techno-economic assessment of the spectrum of LAES concepts so far investigated and 2) the discussion of recent findings on LAES integration with the broader energy system, which the available surveys fail to address. These gaps are interconnected, as techno-economic performance drives LAES uptake and its future value for the energy system and, vice versa, integration studies inform LAES developers on performance and cost targets to be reached. Gap 1) involves the areas of standalone and hybrid LAES, whereas gap 2) concerns the area of LAES integration within the grid, as shown in Fig. 4. By addressing these three areas of LAES research in a single document, the present work uniquely reviews and rationalises also the links and interplay between them.

As noted in the available surveys and extensively detailed in the present work, the breadth of scope, diversity of methodologies and absence of common metrics in the available literature have led to heterogeneous and sometimes contradictory conclusions. Therefore, the main challenge to LAES development lies in the harmonisation of the available knowledge, to lay the foundation for further research. To this end, key contribution and advancements of this piece of work are:

- Systematic review and appraisal of standalone LAES concepts, harmonising the outcomes through a unified benchmarking methodology
- Systematic review and appraisal of hybrid LAES concepts, by extension of the unified benchmarking methodology and cross-comparison
- Methodological review of integration challenges and opportunities for LAES, by detailed analysis of the studies where LAES is operated as part of the energy system

The proposed assessment ultimately enables to cement the current understanding around LAES and, from there, identify the current challenges, promising integration pathways and suggest future research guidelines to unlock the full potential of liquid air energy storage.

2. Materials and methods

2.1. Literature search and selection

A parallel document search was undertaken through the search engines Scopus [32] and Web of Science [33]. To capture the relevant literature, a unique research query was performed in both databases for the words *"liquid air energy storage", "energy storage", "liquid air", "cryogen", "supercritical air"* in the title abstract and keywords. Respectively, 502 and 253 results were found for the period prior to the 1st January 2021. From such initial set, nonrelevant sources were further discarded based on scope, availability, language and, in the case of conference proceedings, the availability of a corresponding journal peer-reviewed paper. Forward and backwards referencing across documents was then carried out to retrieve additional material.

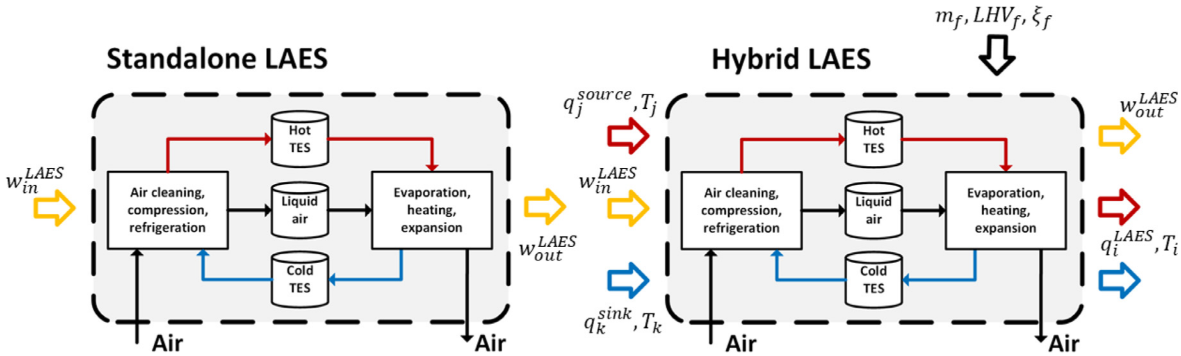

Fig. 5. Concept drawing of a generic baseline liquid air energy storage.

The final pool of selected references on LAES included 125 documents mostly journal papers (94 documents), 21 conference proceedings and 2 book chapters, plus a minor amount of grey literature, reports and patents. Reference journals for the topic are found to be *Applied Energy* and *Energy*, which jointly cover about half of the scientific publications reviewed in this article; other relevant journal titles are *Applied Thermal Engineering, Energy Conversion and Management* (5 relevant publications each), the *Journal of Energy Storage* (3 publications) and the open-access *Energies* (3 publications).

2.2. Proposed framework for literature results analysis

In order to rationalise the outcomes from the 125 references considered, these have been subdivided into three key areas of LAES research as follows: 28 on standalone LAES, 47 on hybrid LAES, 20 on LAES integration; the remainder involves early-stage development and experimental studies or reviews. While studies on standalone and hybrid LAES focus on the technical and/or economic assessment of specific plant layouts *in isolation*, integration studies consider a LAES plant (standalone or hybrid) operating *within* the energy system; they include external details to LAES process and focus on LAES services, value and balancing role. Therefore, it is relevant to carry out a techno-economic cross-comparison between standalone and hybrid LAES concepts and use the resulting Fig.s to assess the outcomes of the integration studies. Although somewhat arbitrary, the proposed distinction creates a suitable framework for a comprehensive discussion of LAES literature.

2.2.1. Standalone and hybrid LAES definition

The distinction between standalone LAES and hybrid LAES is first proposed here to allow meaningful cross-comparison between the vast number of LAES layouts studied over the years. A schematic of the two classes of LAES configurations is depicted in Fig. 5 and a formal definition for standalone and hybrid LAES is given as follows:

- **Standalone LAES**: this class includes the baseline LAES layouts. Input and output energy streams are electricity only; no fluids other than air and the heat carriers responsible for hot and cold recycle within the LAES process itself are present in this configuration.
- **Hybrid LAES**: this class includes all the layouts where LAES interacts with external processes (i.e. it is not standalone) through hot or cold thermal streams, or external fluids such as fuels for combustion. Input and output energy streams can now be electricity, heating, cooling or chemical energy from the fuel; additional fluids may be present.

The formal definition of standalone LAES and hybrid LAES allows to clearly distinguish cases where LAES operates as a self-sufficient (standalone) storage entity from cases where integration with external processes is investigated (hybrid) and thus plant performance requires to be evaluated accordingly.

2.2.2. Unifying framework for LAES technical and economic assessment

A number of LAES performance indicators have been proposed and adopted in the literature as a result of the variety of plant layouts and type of studies carried out. By far the most widespread indicator is the roundtrip efficiency, η_{RT} [34–36]. It represents the ratio between the electricity retrieved and stored over a complete cycle of LAES charging/discharging. Although widely adopted, the use of roundtrip efficiency is strictly suitable to assess performance on standalone LAES, while less appropriate for hybrid LAES involving other forms of energy streams besides electricity (see Fig. 5). For instance, its value is limited below unity for standalone LAES, but not for hybrid plants.

Therefore, in this review, a systematic framework consisting of 3 performance metrics is adopted to coherently assess the performance of each LAES concept and, crucially, to provide a common ground for meaningful cross-comparison between standalone and hybrid LAES. *Electrical efficiency*, η_E, (i.e. roundtrip efficiency) is here used to assess the performance of LAES from the perspective of an external electricity user (e.g. the transmission system operator); the *energy efficiency*, η_I, gauges the overall conversion efficiency of LAES between inputs and outputs and finally *exergy efficiency*, η_{II}, is used to capture the quality of electrical and thermal energy stream when they concurrently occur during hybrid LAES operation. Such metrics were computed as follows:

$$\eta_E = \frac{w_{out}^{LAES}}{w_{in}^{LAES}} \tag{2.1}$$

$$\eta_I = \frac{w_{out}^{LAES} + \sum_i \left| q_i^{LAES} \right|}{w_{in}^{LAES} + \sum_j q_j^{source} + m_f LHV_f} \tag{2.2}$$

$$\eta_{II} = \frac{w_{out}^{LAES} + \sum_i \left| q_i^{LAES}\left(1 - \frac{T_0}{T_i}\right) \right|}{w_{in}^{LAES} + \sum_j q_j^{source}\left(1 - \frac{T_0}{T_j}\right) + \sum_k q_k^{sink}\left(1 - \frac{T_0}{T_k}\right) + m_f \xi_f} \tag{2.3}$$

In the formulae, all quantities are intended per unit liquid air, for consistency. w_{in}^{LAES} and w_{out}^{LAES} are, respectively, the electricity input to LAES charging process and the electric output while discharging. q_i^{LAES} refers to the thermal energy output from LAES during discharge process (see Fig. 5) and it can assume either positive (heating output) or negative (cooling output) values. For hybrid concepts, m_f represents the mass of injected fuel per unit liquid air; the associated lower heating value is LHV_f, which also approximates fuel's chemical exergy, ξ_f [37,38]. Finally, q_j^{source} and q_k^{sink} quantify the thermal interactions of LAES with the environment or neighbouring process.

Concerning elaboration of the economic results, estimations of the specific investment costs per unit power output and capacity were systematically collected and subdivided across standalone and hybrid LAES. This way, 14 LAES concepts were reliably quantified based on the available references. When this was not the case (especially for hybrid LAES), cost functions were used for obtaining economic estimates.

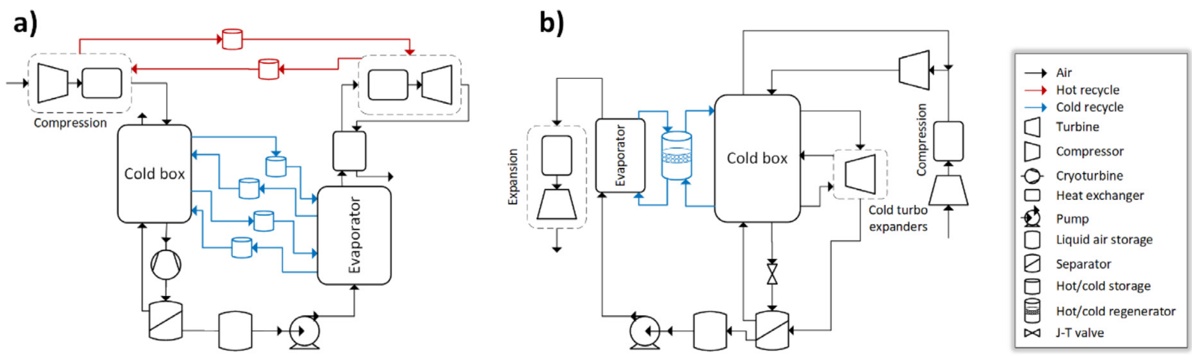

Fig. 6. Two representative process layouts of standalone LAES. a) Linde-Rankine with hot and cold recovery (adapted from [39]), b) Kapitza-Rankine with external cold expansion and cold recovery (adapted from [40]).

This allowed to compare different layouts and hybrid versus standalone solutions, as well as compare LAES with other storage technologies. All costs were expressed in 2017€, using the yearly conversion factors published by the UK government[1].

3. Standalone LAES

Table 2 summarises the reviewed studies on standalone LAES plants – these cover a steady portion of LAES literature, with an average of almost 5 new publications per year, from 2015, onwards. Various layouts and technological solutions have been proposed, mainly concerning LAES charge and thermal recycle subsystems; on the contrary, a Rankine cycle is the typical choice for the PRU. For illustrative purposes, two standalone LAES process layouts are reported in Fig. 6: they showcase different choices for liquefaction, PRU and thermal recycle layouts.

From a methodological standpoint, most works listed in Table 2 investigated LAES thermodynamic performance through process modelling, energy and exergy analysis, parametric studies and optimisation. Commercial simulation tools such as ASPEN or gPROMS were commonly used, or in-house codes developed in MATLAB, EES, etc. Only more recently, combined thermo-economic analysis has been used to characterise investment costs and financial viability of LAES, across different layouts [41,42] or in comparison with other storage technologies [43]. There is also scarce availability of experimental data from real-life demonstration LAES projects, currently limited to two documents on the 350 kW pilot plant [44,45]. They report process variables evolution under different output setpoints, as well as field trials to test LAES suitability for a range of power balancing services (e.g. STOR or load following in the PJM). However, as recently pointed out by Borri *et al.* [31], it is essential for technological development and implementation of LAES that additional experimental evidence is gathered and disseminated among the research community. This is one of the limitations currently hindering LAES development as compared to thermo-mechanical technologies such as PHES or CAES, which rely on extensive experimental evidence and years of practice.

In terms of process scales, performance assessment is sometimes carried out per unit liquid air [39]; when this is not the case, LAES plants from 10 to 100 MW output are typically considered. Power input to the liquefier is generally lower (10-50 MW), as more off-peak hours are available for charging (e.g. 8-10 hours overnight), but in few cases, when the same charge/discharge time is targeted, larger liquefiers are considered [41,46]. In the following, further discussion around Table 2 for standalone LAES is organised by key processes.

[1] https://www.gov.uk/government/publications/exchange-rates-for-customs-and-vat-yearly

3.1. Air liquefaction process

State-of-the-art, recuperative gas liquefaction processes are used for air liquefaction [59]; typical cycle layouts considered for LAES applications are reported in Fig. 7. They all comprise initial filtering and dehumidification of the feed air with molecular sieves, to avoid freezing. Then, common steps are intercooled gas compression, heat removal and expansion in Joule-Thomson valves or cryogenic turbines [60]. The combined cooling effect from heat transfer with the colder return stream and the direct expansion of the working fluid results in its liquefaction. Depending on the process layout, special multi-stream heat exchangers with tailored design (the so-called cold box) are necessary. They may be of coil-wound type or diffusion bonded, with the latter option ensuring extreme pressure resistance (above 500 bar [61]) and great compactness thanks to above 2500 m^2/m^3 exchange surface per unit volume [62].

Comparative exergo-economic analysis of six liquefaction cycle layouts by Hamdy *et al.* [63] indicates that Claude, Heylandt and Kapitza are comparable in performance and significantly outpacing the alternatives. They are preferable to Collins due to fewer expanders at comparable liquefaction performance, which is four times higher than a Linde cycle [64]. Analogous conclusions were suggested by Borri *et al.* [65], for a small-scale liquefier of about 1 ton/h. Claude, Heylandt and Kapitza are indeed the most widespread liquefaction layouts, according to Table 2. Partial cycle modifications involve adjustments of the external expansion and recirculation circuit through the cold box, to enhance the cooling effect by limiting heat exchange irreversibility [40] or substitution of the Joule-Thomson valve with a cryoturbine, which led to a 6.9% improvement of system performance [48].

In terms of process parameters, pressure at the outlet of the compression stage (i.e. inlet pressure of the cold box) directly affects streams' temperature evolution in the cold box, with higher pressures resulting in a greater cooling effect on the incoming air. This allows reaching a higher liquid yield, up to a point where further improvement from pressure increase is precluded by pinch point limitations at the cold end of the cold box. Thus, an optimal operating pressure exists, which corresponds to the condition minimising entropy generation in the cold box [39]. The optimal pressure value necessarily differs for alternative liquefaction layouts [63], but operating conditions above 120 bar are generally chosen (see Table 2). Alongside operating pressure, the fraction of air recirculation can be also optimised to ensure higher liquid yield [50,65]. Pressurised storage vessels are also beneficial for liquefaction performance but result in higher air saturation temperature and thus lower storage energy density [55]. In this regard, Borri *et al.* [65] claimed 21% lower specific energy consumption for the liquefier when storing air at 4 bar rather than ambient conditions. Values as high as 210 bar were explored [66], even if a much lower 18 bar was considered by the same authors in recent publications [67], for technical feasibility. Overall, the optimal design of pressurised vessels depends on storage capacity and should be the result of a techno-economic trade-off

Table 2
Summary of the most relevant studies dealing with standalone LAES.

Reference	Standalone LAES plant description				Methodology	p levels [bar]		Specific work [kJ/kg]		η_{RT}** [%]	ECO Value	Findings	Notes
	AL	PRU	Hot/cold recycle	Cap [MWh]		AL	PRU	AL	PRU				
Guizzi *et al.* 2015 [39]	Linde	Rankine	H: thermal oil - 2 tanks C: propane and methanol - 2 tanks	N.A.	TD	181	65	787*	428.2	54.4	N.A.	Link parameters-performance Optimal charging pressure	Specific analysis
Morgan *et al.* 2015 [44]	Claude	Rankine	C: air - packed bed	2.5	EXP	12	56	1560*	125*	8	N.A.	Fully integrated LAES proven 32% higher efficiency with cold recycle	Experimental 51% cold recycled
Morgan *et al.* 2015 [40]	Kapitza 14.2* MW	Rankine 20 MW	H: N.A. C: air - packed bed	80	TD ECO	56.2	190	708.5*	333*	47.0	995-1774 £/kW 150-100 £/MWh	Liquefier optimisation necessary	Cold store design
Xue *et al.* 2015 [47]	Linde	Rankine	H: N.A. C: air - regenerator	N.A.	TD	140	70	N.A.	N.A.	49.0	N.A.	Benefit from improved component efficiency	Simultaneous charge/discharge
Guo *et al.* 2016 [48]	Linde	Rankine 10 MW	H: thermal oil - 2 tanks C: air - regenerator	10	TD	120	95	584.6*	394*	67.4	N.A.	Liquid expander brings 7 points η_{RT} increase Energy density 18 times CAES	High-pressure vessel
Hamdy *et al.* 2017 [49]	Heylandt 12.5* MW	Rankine 10 MW	H: water C: R218 and methanol - 2 tanks	40	TD	180	150	1062*	429	40.4	N.A.	Indirect ORC for PRU increases output but 16.4% efficiency	Hybrid LAES concept
Sciacovelli *et al.* 2017 [50]	Kapitza 70 MW	Rankine 100 MW	H: thermal oil - 2 tanks C: air - packed bed	300	TD	185	75	978	472	48.3	N.A.	Cyclic LAES operation needed	Dynamic packed bed model
She *et al.* 2017 [46]	Linde 95 MW	Rankine 48 MW	H: thermal oil - 2 tanks C: propane and methanol - 2 tanks	N.A.	TD	90	120	872*	440*	50.0	N.A.	Up to 40% compression heat is wasted	No losses from cold TES
Xie *et al.* 2018 [51]	Linde	Rankine	H: N.A. - 2 tanks C: N.A. - regenerator	N.A.	TD	80	70	996*	458*	46.0	N.A.	Pressure effect on charge and discharge performance	Extensive sensitivity analysis
Sciacovelli *et al.* [45]	Claude	Rankine	C: air - packed bed	2.5	EXP	12.2	46	N.A.	N.A.	N.A.	N.A.	Stable output over 3 setpoints Process variables evolution	Experimental LAES discharge
Peng *et al.* 2018 [52]	Linde	Rankine	H: air - packed bed C: air - packed bed	5.6	TD	121	50	818*	462*	56.3	N.A.	Lower efficiency than CAES but 10 times higher energy density Scale above 100 MW	Comparison with A-CAES Dynamic hot TES
Peng *et al.* 2018 [53]	Linde	Rankine	H: thermal oil - 2 tanks C: propane and methanol - 2 tanks	N.A.	TD	140	80	731.9	434.7	59.4	N.A.	Lost cold recycle 7 times more impact than lost hot	No losses from cold TES
Tafone *et al.* 2018 [54]	Kapitza	Rankine 10 MW	H: Therminol 66 - 2 tanks C: air	N.A.	TD	110	180	874.8	421.8	48.2	N.A.	System improvement by layout and waste heat recovery	8 bar pressurised vessel 55% waste heat recovery

(*continued on next page*)

Table 2 (*continued*)

Reference	Standalone LAES plant description				Methodology	p levels [bar]		Specific work [kJ/kg]		η_{RT}** [%]	ECO Value	Findings	Notes
	AL	PRU	Hot/cold recycle	Cap [MWh]		AL	PRU	AL	PRU				
Georgiou *et al.* 2018 [43]	Claude	Rankine 12 MW	H: N.A. Cd: N.A.	50	TD ECO	170	N.A.	N.A.	N.A.	31.5	1.4-2.8 k$/kW	Better economy than PTES (at large power especially)	3 costing approaches
Kim *et al.* 2019 [55]	Linde 51.5 MW	Rankine 100 MW	H: N.A. - 2 tanks C: N.A. - 2 tanks	200	TD	120	N.A.	N.A.	N.A.	64.7	N.A.	Pressurised LAES with 9 points efficiency increase	Pressurised vessel, 45 bar
Lin *et al.* 2019 [56]	Kapitza 16.7 MW	Rankine 9.9 MW	H: thermal oil - 2 tanks C: air - 2 T level packed bed	N.A.	TD	120	87.7	604*	359*	59.4	N.A.	Efficiency increases to 65% if storage at 9 bar	Sensitivity on vessel pressure
Hamdy *et al.* 2019 [41]	Heylandt 107* MW	Rankine 100 MW	H: pressurised water - 2 tanks C: R218 and methanol - 2 tanks	400	TD ECO	120	160	994*	465*	46.8	2087 €/kW	60% investment cost maintaining efficiency above 40%	Trade-off efficiency vs investment cost
Legrand *et al.* 2019 [57]	Kapitza 72.5 MW	Rankine 100 MW	H: thermal oil - 2 tanks C: air - packed bed	300	TD	180	75	1068*	552	51.2	N.A.	52% efficiency with detailed modelling, 235 Wh/L	Dynamic cold regenerator
Guo *et al.* 2020 [58]	Multiple 19.5* MW	Rankine 9.8* MW	H: N.A. - 2 tanks C: air - 2 T level packed bed	79	TD ECO	70	57.4	703*	433*	61.6	Depends on site	107 kWh/m^3 Claude less sensitive to TES efficiency	Extensive sensitivity analysis

Abbreviations: AL: air liquefaction, PRU: power recovery unit, Cap: capacity, H: hot, C: cold, TD: thermodynamic, ECO: economic, EXP: experimental.

* Computed by the authors based on available data.

** Value indicated in the referenced publication - Results from the unifying methodology proposed in this review are reported separately.

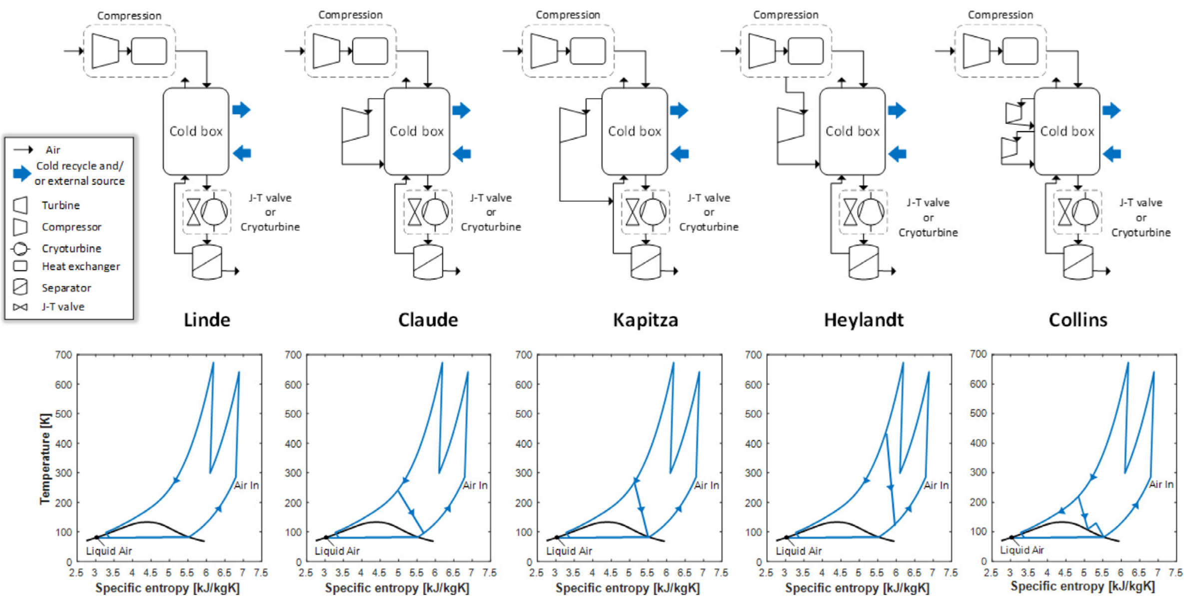

Fig. 7. Air liquefaction process layouts typically considered for LAES application and associated T-s diagrams.

Table 3
Typical operating parameters of LAES liquefaction process.

Parameter	Typical values
Compressor isentropic efficiency	85-90%
Number of compression stages	2-4
Cryoturbine efficiency	65-85%
Heat exchangers effectiveness	90-95%
Heat exchangers pinch point	1-10°C
Maximum cycle pressure	40-200 bar
Storage vessel pressure	1-45 bar
Liquefaction work (with cold recycle)	163-297 kWh/ton
Liquid yield (with cold recycle)	0.6-0.95
Recirculation fraction	0-0.3

between plant efficiency and cost of high-pressure vessels, which so far has not been addressed.

The common values of technical and operating parameters associated with LAES liquefaction cycle can be found in Table 3. Proper selection of the parameters, together with effective cold recycle (as further discussed in Section 3.3) allows obtaining high liquefaction performance for LAES in comparison with commercial gas liquefaction plants [68]. Typical values of specific liquefaction work for LAES attest around 200-300 kWh for the production of 1 ton of liquid air [40,53], which corresponds to a ~30% reduction in comparison with state-of-the-art cryogenic cycles (320-330 kWh/ton; 0.28-0.29 kWh/Nm) [60]. Analysis of the information collected in Table 2 show even lower specific liquefaction work can be reached (163 and 168 kWh/ton, respectively), but only with pressurised liquid air storage tanks [48,56]: pressurised vessels allow smaller Δp for air expansion through the Joule-Thomson valve or the cryoturbine, which results in higher liquid fraction at the outlet.

3.2. Power extraction from liquid air

When electricity is required, LAES is discharged and work is retrieved from the stored liquid air. Although various power cycles are possible, a direct Rankine with air as working fluid is typically the preferred option (see Fig. 8) since the selection of the cycles is mainly driven by temperature and availability of the hot source [69]. Leaving the cryogenic tank, liquid air is pumped to supercritical pressures using

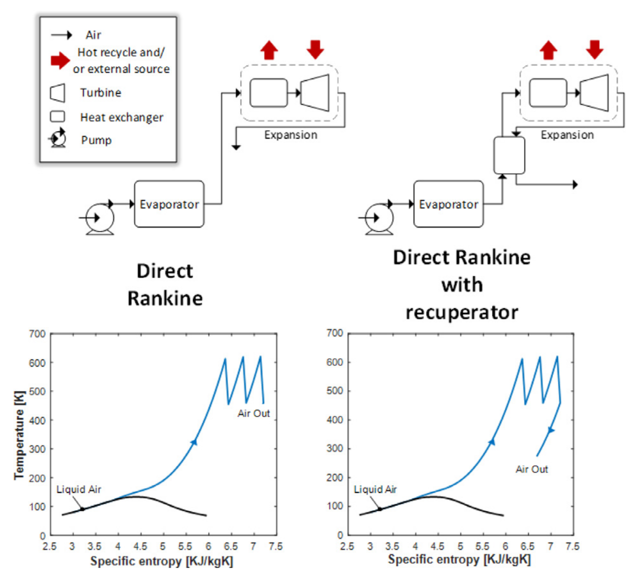

Fig. 8. Power generation process layouts typically considered for LAES application and associate T-s diagrams.

feed pumps commonly used in the liquefied natural gas (LNG) industry [70]. Liquid air is then evaporated and expanded in multiple turbine stages with intermediate reheating. The efficiency of both heat exchangers and expansion devices were identified as key for achieving high values of power output [71]. Compact, flat plate geometries are typically selected for the heat exchangers, whereas radial inflow turbines or axial turbomachinery of gas derivation are employed depending on the rated discharge pressure and power output [22].

Depending on the combined effect of reheating temperature and turbine expansion ratio, turbine outlet conditions may still be above ambient temperature. In this case, an additional recuperative heat exchanger can improve process efficiency, using outlet excess heat to preheat the air stream before the expansion train [39,50]. Increasing the number of turbine stages to better match isothermal expansion was also proven as a viable option to boost power output, although involving higher investment costs [22].

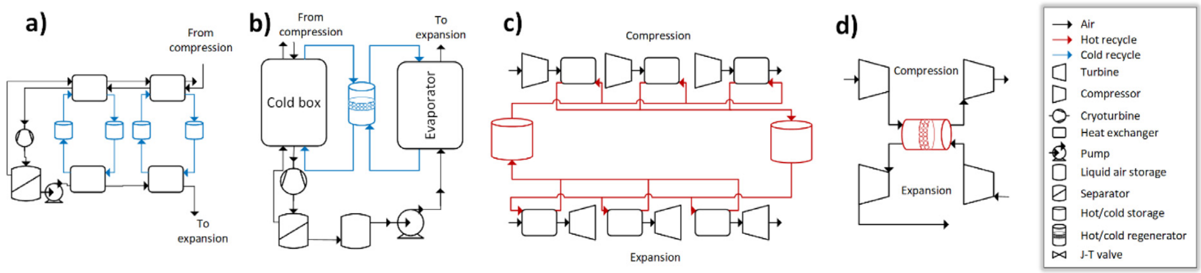

Fig. 9. Technological solutions for LAES cold and hot recycle, adapted from literature. a) two-tank, two-fluid cold recycle [80], b) high grade cold packed bed [57], c) two-tank, one-fluid hot recycle [48], d) hot packed bed [52].

Table 4
Typical operating parameters of LAES power recovery unit.

Parameter	Typical values
Turbine isentropic efficiency	80-90%
Turbine inlet temperature	140-260°C
Number of expansion stages	2-5
Heat exchangers effectiveness	90-95%
Heat exchangers pinch point	1-10°C
PRU maximum pressure	55-200 bar
Cryogenic pump efficiency	70-90%
Specific work output	333-552 kJ/kg

As far as the operating parameters are concerned, an increase of the discharge pressure is widely recognised as beneficial for higher specific work output and more effective heat transfer in the evaporator [50], although reducing the cold which can be recovered [72]. Values above 50 bar and up to 150 bar are typically selected, in the supercritical region for air (see Table 2). Effects of supercritical heat transfer during LAES evaporation were investigated by Yu *et al.* [24], who suggested an optimal heat exchanger configuration with two consecutive stages where the mass flow rate of the secondary fluid can be adjusted to overcome pinch point limitations. Depending on the pressure, 61-67% of the evaporation heat of liquid air is exchanged in the low-temperature section, below 200 K.

High reheating temperatures are also essential to enhance the LAES power output. Several hybrid concepts have been proposed specifically for this purpose, including the exploitation of external waste heat or fuel combustion upstream turbine expansion. In the case of standalone LAES, efficient compression heat recycle is crucial to attaining higher expansion inlet temperatures. Typical technical and operating parameters for LAES discharge are reported in Table 4.

3.3. Hot and cold thermal recycle

Hot and cold energy streams are produced at different stages of LAES charge and discharge and required at others. More specifically, high-grade cold produced during air evaporation can support air liquefaction, while compression heat can be used as the high-temperature thermal reservoir, during reheating. Efficient storage and internal use of such streams within LAES process is key to plant performance, particularly concerning cold recycle, where cold energy losses were observed to yield a seven-times higher impact on LAES efficiency than heat losses in the hot recycle [53]. Several technological solutions for thermal recycle have been proposed which adopt different heat transfer fluids, storage media and TES configurations; the most typical options are illustrated in Fig. 9.

Initially proposed to reduce liquefaction work through air precooling upstream compression [15], the high-grade cold from liquid air evaporation boosts LAES performance the most when providing extra cooling in the cold box. Evaporation temperatures ~90 K require material stability at cryogenic conditions, hence solid regenerator-type storage solutions have initially been proposed for cold recycle. These include a 304 stainless steel solid matrix [12], steel pipes filled with concrete pebbles [15] or a packed bed of rocks, as adopted in the plants by Highview Power [40]. Besides storage medium availability, thermal stability and low cost, the key benefit of regenerators is direct heat transfer. Cryogenic packed beds have been mainly analysed through dynamic numerical models [45] or experimentally investigated [26]. Experimental results are highly valued here, given the challenge of extrapolating thermal properties and their variation with temperature, in the cryogenic range [73]. Hüttermann and Span [74] compared 9 solid materials suitable for temperatures between 0 and -196°C, highlighting a trade-off between energy and exergy efficiency of the cold TES device and ranking the commonly adopted quartzite among the best. Experimental measurements under cyclic operation report thermal efficiency (i.e. the ratio between the heat input during TES charge and TES thermal output in the following discharge) as high as 95% for cryogenic packed beds [75], showing high effectiveness and low losses for regenerators. On the other hand, thermal front development in the regenerators (thermocline) results in larger storage volumes required and dynamic temperature variations at the TES outlet [76]. Technical solutions such as partitioned TES layouts have been proposed [77] and implemented [40] to alleviate this effect, at the expense of increased complexity and cost of the TES device.

Liquid TES solutions have also been proposed in the literature for cold recycle. Given no suitable fluid is liquid across the entire span from 0 to -196°C, two fluids were proposed for cold storage over increasing temperatures, such as propane (R290) and methanol [39,58], or R218 and methanol [49]. R123 is liquid over a larger temperature range and may replace methanol [78]; such propane-R123 layout has recently shown 91% thermal efficiency for a small-scale test facility with vermiculite insulation, hence proving slightly higher thermal losses than solid packed bed concepts. The key advantage of liquid TES is compactness [39]. However, for safety reasons, oxygen in the liquid air streams must be kept separate from liquid hydrocarbons [79]. An intermediate N_2 circuit may be used to decouple LAES process from the cold recycle loop, with an increase in equipment cost and thermal degradation due to indirect heat transfer.

Concerning hot recycle, its main use is to increase the turbine inlet temperature by using the compression heat released during liquefaction. Here it is worth mentioning that not all the rejected can be used and a rejection of ambient heat exchanger is often part of the circuit. A two-tank system with liquid TES is common practice in this case and only one study investigated the use of a hot packed bed TES for hot recycle, similarly to what proposed for adiabatic CAES [52]. Pressurised water for temperatures <180°C [48] or diathermic oils above [39] have been proposed as heat carriers and storage media. Two separate fluids (e.g. water and oil) can also be adopted, over increasing temperature levels [81], which can result in more favourable temperature glide for coupling with external power cycles. Two fluids are necessary also if molten salts are proposed as heat carrier, such as in [82], where mineral oil is used

Table 5
Most commonly used TES media and technological solutions for LAES hot and cold recycle.

Medium	Techical solution	Specific heat [kJ/kgK]	Density [kg/m^3]	T range [K]	Notes
Quartzite	C, PB	0.5-0.6	2560-2650	80-293	Variable properties, cost ~0
Propane	C, 2-T	1.9-2.3	732-581	93-210	High-grade cold only
R218	C, 2-T	0.8-0.9	1711-2137	93-210	High-grade cold only
Methanol	C, 2-T	2.2-2.4	904-810	210-293	Low-grade cold only, cost ~0.4 $/kg
R123	C, 2-T	0.9-1.0	1477-1727	185-293	Low grade cold only
Water	H, 2-T	4.2-4.4	890-998	300-450	Pressurisation needed, cost ~0
Solar salt	H, 2-T	1.6	1900	493-873	Solidifies for lower T, cost ~0.5 $/kg
Diathermic oil	H, 2-T	2.2-2.4	750-850	293-630	Cost ~1 $/kg
CaLiNaK	H, 2-T	1.7	1917	373-673	Solidifies for lower T
Steatite	H, PB	0.8-0.9	2680	250-573	Variable properties, cost ~0

Abbreviations: H: hot recycle, C: cold recycle, PB: packed bed regenerator, 2-T: two-tank liquid TES.

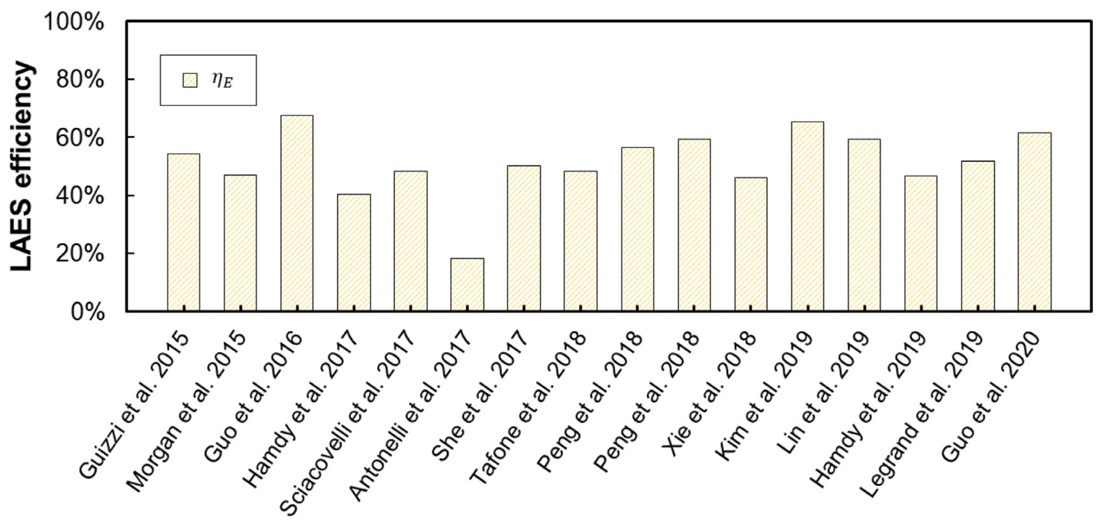

Fig. 10. Technical assessment of different standalone LAES plants, based on the proposed performance metrics.

for low-temperature storage and solar salt handles the compression heat portion above 220°C (its phase transition temperature). A recent screening of phase change material properties, highlighted nitrate-based salts with energy density of 2.8-3.1 MJ/m^{3}K, such as CaLiNaK 4 and 11, as viable options to contain volumes and costs [83,84] of LAES hot recycle; a second fluid for temperatures below 100°C would still be needed in this case.

The most common storage media, their thermophysical properties and the associated technological solutions for thermal recycle within LAES are reported in Table 5. Liquid and solid TES have specific pros and cons: highly efficient but less compact regenerators face more challenging dynamic operation, whereas highly energy-dense but less thermally efficient two-tank liquid storage layouts benefit from a steady and well-known process. Given the documented importance of cold recycle for LAES performance, choices lean towards thermally efficient solid regenerators for cold TES. Operability and steady turbine inlet temperatures are preferable during LAES discharge, so two-tanks liquid TES should be chosen for hot recycle, with temperature levels driving suitable storage media and fluid selection. Considerations on costs and a comparative techno-economic assessment of TES alternatives may provide additional rationale to design choices; however, such analysis has yet to be undertaken for LAES.

3.4. Techno-economic assessment

The proposed performance metrics, namely electrical, energy and exergy efficiency (see section 2.2.2 for individual definitions) were computed for all the LAES layouts reviewed in Table 2. In Fig. 10, electrical efficiency only is reported, which is sufficient to compare coherently the performance of standalone LAES plants across the studies gathered in this review. Computed efficiency Fig.s mainly vary between 40.4% and 61.6%, with a mean value of 49.3%. 18% efficiency is predicted by Antonelli *et al.* [87] when ambient-temperature air is used as heat source for the reheating process. On the other hand, efficiency above 60% is predicted for very high cryogenic pump efficiency, which results in lower temperatures in the cold recycle and thus liquefaction yield close to unity [48]. Similar performance is also reached when the storage tank pressure is increased, up to 45 bar, in a pressurised cryogenic air energy storage concept [55]. Computed efficiency values are 67.4% and 65.2%, respectively, in these two cases. More discussion on the values of the proposed metrics for standalone LAES and, crucially, cross-comparison with hybrid LAES is left to section 4.4.

Complementary to a technical appraisal and serving as a starting point for any economic assessment, several studies addressed the quantification of LAES investment cost (CAPEX). Reviewed results for standalone concepts are presented in Fig. 11, in 2017€ units.

Values for standalone LAES range significantly and mainly between 1.3 and 2.2 k€/kW. Such large interval stems primarily from the different methodologies adopted, which include the use of cost functions for individual components [43] or groups of components [88], industrial quotations from manufacturers and industrial suppliers [40] or use of specific costing software [89]. A combination of such methods has also been used to overcome the lack of generic cost functions for specific devices such as customised cold TES or evaporator [41]. Besides supply chain quotations, a learning rate of 17,5% was included in the analysis by Morgan *et al.* [40], to derive costs for a 10-th of a kind plant, even if the off-the-shelf nature of LAES components and their established supply chain may prove such assumption and associated results (995£/kW) as overoptimistic. More informative is the study from Georgiou *et al.* [43], where three costing approaches were compared to make

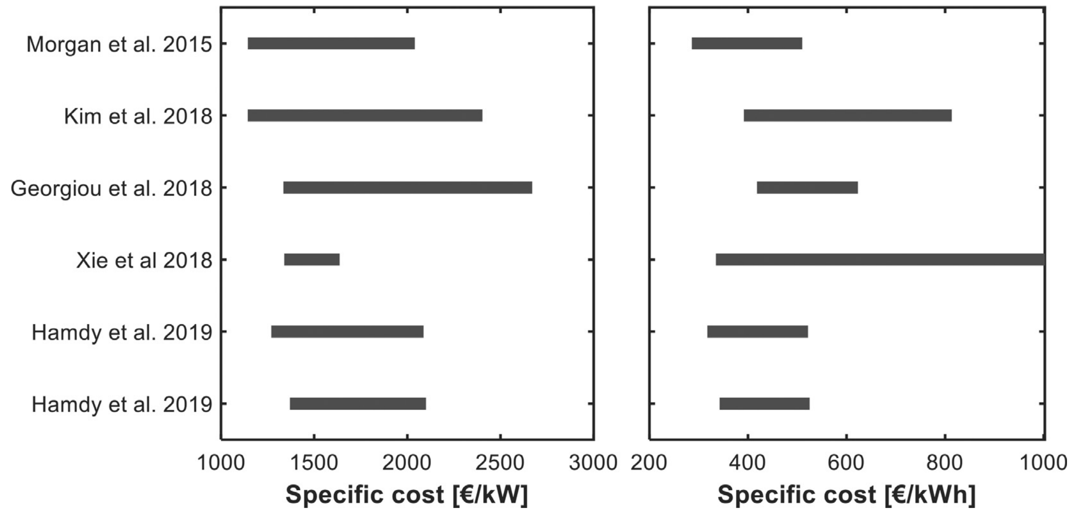

Fig. 11. Indicated values of specific investment cost for a standalone LAES.

up for the underlying uncertainty associated with cost functions. A confidence interval on the investment costs, rather than a conclusive Fig., was derived from such analysis: values are comparable with those for other thermo-mechanical storage technologies, although obtained for a rather small (12 MW) LAES plant. Economies of scale would further decrease specific CAPEX, stressing the importance of considering appropriate system sizes, for both characterisation and comparison purposes. Indeed, specific investment more than halved, from 5 to 2.1 k$/kW, for a 12MW/50MWh LAES, with respect to a 2 MW/11.5 MWh plant [43]. Similar considerations apply when comparing a 100 MW and a 300 MW plant, with respective specific cost of 2100 and 1400 k€/kW [42].

Looking at the breakdown of costs, references agree on the large impact of power equipment (turbines and compressors) and the major contribution by the liquefaction subsystem, which, depending on the case, represents from 45% to 70% of the total investment cost; liquid air and TES tanks share is limited below 10% [43,88]. Efficient cold recycle is thus paramount not only for boosting technical performance but also for enhancing LAES economy by containing liquefaction power rating. Similar techno-economic implications for standalone plants have been largely investigated by Hamdy *et al.* [41]. Trade-offs can be achieved between roundtrip efficiency and investment cost, by suitably modifying parameters such as compression pressure, re-heater outlet temperature and the heat carrier fluid at design stage. Specific costs for a 100 MW/400 MWh standalone LAES plant could be significantly reduced from 2087 €/kW to 1270 €/kW, with a moderate efficiency reduction from 47% to 40%.

4. Hybrid LAES

An overview of studies addressing hybrid LAES concepts is reported in Table 6, where it can be appreciated how hybrid LAES has recently emerged as an alternative to standalone systems. The vast hybridisation options offered by LAES is a rather unique feature, and alternative paths have been followed. A first research thread involves hybrid concepts where external fuels and/or heat/cold energy streams are used to enhance the techno-economic performance of standalone LAES [87,90]. Alternatively, LAES can be coupled with full-scale nearby processes such as power plants, LNG terminals and organic Rankine cycles (ORC). Such integration, as thoroughly detailed in this section, creates opportunities for co-designing and symbiosis between the processes – for instance, through waste heat recovery – which often leads to mutual performance enhancement [91,92]. The most recent research pathway relates to the additional functions and benefits that hybrid LAES can provide to nearby processes, alongside electricity storage capabilities (e.g. thermal output, industrial gasses, etc.) [37,93]. Discussion in the next sections expands on each of these three pathways.

Some notable examples of hybrid LAES layouts are shown in Fig. 12; depending on the specific case, key benefits, when compared to standalone plants are: i) efficient utilization and exploitation of the energy streams internal to the LAES process (e.g. better heat/cold reintegration), ii) recovery of waste heat and waste cold from near-by sources (e.g. industrial sites), iii) overall increased power output, compactness and enhancement of flexibility of traditional power generation systems (e.g. thermal plants, nuclear plants). Accordingly, concepts in Fig. 12 rank differently based on the metrics proposed: 129% electrical efficiency is reported for the LNG regasification + LAES due to the extra power production by the indirect ORC and the external high-grade cold input to LAES, the trigenerative LAES configuration achieves the highest energy efficiency (72.1%) thanks to multi-vector output and the hybrid LAES-PTES scores high in exergy efficiency (60.5%). As further discussed in section 4.4, these metrics better describe different LAES layouts and put them into perspective. On the other hand, hybridization of LAES might lead to increased system complexity which requires dedicated operational strategies accounting for added technical constraints (e.g. time availability of the process-coupling energy streams). As can be inferred from Table 6, such challenges are only partially addressed in the literature, mainly through thermodynamic and economic analysis, parametric studies and optimisation at process scale.

4.1. LAES performance enhancement using external streams and power cycles

Studies reported in Table 6 agree in showing mainly LAES charging process – i.e. the air liquefaction section – to benefit from hybridization. In this regard, the use of waste cold streams, and specifically the high-grade cold released during LNG regasification offers an attractive option [81,99], enabling to increase liquid yield to 0.87 and reducing liquefaction work to 580 kJ/kg [18]. Alongside the cooling effect, LNG has also been proposed to serve as the cold source for a nitrogen Brayton cycle [80,111], which allows to fully use compression heat and greatly improves the power output up to 300 kJ per unit mass of LNG. Alternatively, air liquefaction could also be supported by an adsorption chiller driven by the internal compression heat otherwise rejected. This way, liquefaction work can be reduced to 478 kWh/ton [100], with a modest 3% rise in plant roundtrip efficiency [112]. However, no studies follow-up on the addition of adsorption chillers for internal use, because a higher air liquefaction efficiency ultimately reduces the compression heat which is available to drive the chiller.

Table 6
Summary of the most relevant studies dealing with hybrid LAES.

Reference	Hybrid LAES layout	Methodology	Advantages	η_{RT}* [%]	ECO value	Findings	Notes
Li *et al.* 2011 [38]	Open LA power cycle + closed CH_4 Brayton	TD	Peak shaving opportunity Cryogenic CO_2 capture	54.0	N.A.	Peaker size could be halved	Peaker operation Conversion coefficient for ASU
Li *et al.* 2012 [96]	Open LA power cycle + closed solar Brayton	TD, SQP opt	Peak shaving opportunity No combustion	N.A.	N.A.	Above 30% higher power than separate sub-systems	Peaker operation Conversion coefficient for ASU
Li *et al.* 2013 [97]	Open LA power cycle + closed oxyfuel Brayton	TD, ECO, GA opt	Peak shaving opportunity Cryogenic CO_2 capture	N.A.	0.08-0.17 $/kWh peak generation	Competitive cost with CCGT Liquid gas from ASU can be sold	ASU constantly run Conversion coefficient for ASU
Li *et al.* 2014 [91]	LAES + nuclear power plant	TD	Nuclear power plant flexibility	70.0	N.A.	Peak power delivered increases by a factor 3	Storage capabilities Thermal input at 560 K
Kantharaj *et al.* 2015 [98]	Co-designed LAES-CAES	TD	No geographical constraints Large capacity	N.A.	N.A.	Conversion compressed-liquid air: 62% forward, 67% backwards	Not economic unless charging above 36h
Lee *et al.* 2017 [66]	Co-designed LAES-LNG	TD	Fully integrated system No air recirculation in AL	172.0	N.A.	High exergy efficiency	Vessel pressure 200 bar
Al-Zareer *et al.* 2017 [37]	LAES + absorption chiller + CH_4 combustion	TD	Full use of compression heat Multi-vector output	72.0	N.A.	Technically feasible Efficiency depends on cooling temperature	Detailed modelling of absorption cycle
Luyao *et al.* 2017 [99]	LAES + LNG + ORC	TD	Low power input and extra power output	60.0	N.A.	Higher system performance from integration	Results dependence on LNG provision
Borri *et al.* 2017 [100]	LAES + absorption chiller	TD	Chiller supports AL Direct use of compression heat	N.A.	N.A.	10% lower liquefaction work Higher exergy efficiency	Study of Kapitza liquefaction process alone
She *et al.* 2017 [46]	LAES + ORC	TD, ECO	Better use of compression heat	55.5	PBT below 3 years	ORC bottoming cycle gives 9-12% η_{RT} improvement and short PBT	Economic study on ORC addition only
Ji *et al.* 2017 [101]	LAES + solar	TD	Higher reheating temperature with no combustion	45.0	N.A.	Feasible system Reasonable efficiency	Compression heat not recycled TES for solar needed
Kim *et al.* 2018 [89]	LAES + LNG + CH_4 combustion	TD, ECO	Simultaneous power generation from LNG and air	72.0	1300 $/kW	High efficiency Similar economic value to CAES	Regenerator to recover LNG cold
Peng *et al.* 2018 [53]	LAES + ORC + absorption chiller	TD	Full use of compression heat	61.3	N.A.	High heat usage ORC alone has higher efficiency	System complexity
Zhang *et al.* 2018 [102]	LAES + LNG + multistage ORC	TD	LNG assists liquefaction Evaporation cold partially used for power production	45.4	N.A.	High efficiency and energy density Pressures are key parameters	System complexity
Farres-Antunez *et al.* 2018 [82]	Co-designed LAES-PTES	TD	Cold TES in LAES and PTES not necessary Simultaneous charge/discharge	70.0	N.A.	High energy density Layout optimisation opportunities	Full liquefaction in the cryoturbine
Krawczyk *et al.* 2018 [90]	LAES + CH_4 combustion	TD	Higher specific work output Large plant: 271.5 MW	55.2	N.A.	Specific work output 905 kJ/kg	Comparison with CAES Compression heat not recycled
Tafone *et al.* 2018 [54]	LAES + ORC	TD	Full use of compression heat	54.4	N.A.	Improvement in η_{RT} and waste heat utilisation	85% use of compression heat
Tafone *et al.* 2018 [54]	LAES + ORC + absorption chiller	TD	Full use of compression heat Multi-vector output	54.4	N.A.	Unchanged η_{RT} 30% higher energy output if trigenerative	90% use of compression heat
Cetin *et al.* 2019 [103]	Co-designed LAES-geothermal	TD	Reduced geothermal losses Fully dispatchable plant	46.0	N.A.	Full system efficiency 24% Flash pressure to be optimised	Compression heat not recycled

(continued on next page)

Table 6 (*continued*)

Reference	Hybrid LAES layout	Methodology	Advantages	η_{RT}* [%]	ECO value	Findings	Notes
Zhang *et al.* 2019 [81]	LAES + Kalina cycle	TD	Better temperature match in the ORC evaporator	57.0	N.A.	η_{RT} from 52% to 57% 55%-75% heat utilisation	80 bar charge pressure 40 bar discharge Multi-level hot TES
Lee *et al.* 2019 [67]	Co-designed LAES-LNG	TD, SRQPD opt	Fully integrated system No air recirculation in AL	130.0	N.A.	Feasible system Air can be fully liquefied	Reduced pressures from initial layout
Peng *et al.* 2019 [18]	LAES + LNG	TD	Independent operation of LAES and LNG through cold storage	78.0	N.A.	High liquid yield and η_{RT} between 78% and 89% Effect of ambient temperature	Year-round performance estimates
She *et al.* 2019 [80]	LAES + LNG + N_2 power cycle	TD	LAES and LNG operate simultaneously LNG as sink for N_2 cycle	72.0	N.A.	Roundtrip comparable with large storage solutions	Effect of Brayton outlet pressure studied
Lee *et al.* 2019 [92]	Co-designed LAES-LNG + ORC	TD, ECO	Full use of LNG evaporation cold through ORC	N.A.	NPV 8-32 M$	High exergy and energy efficiency Low cost	70% exergy efficiency
Zhang *et al.* 2020 [104]	LAES + ORC and LAES + Kalina cycle	TD	Cascaded hot recycle	57.0	N.A.	ORC and Kalina cycle perform similarly but ORC is less complex	Alternative bottoming cycles compared
Wu *et al.* 2020 [85]	LAES + TCES	TD, ECO	High temperatures High energy density	47.4	2130 $/kW	36.8 kWh/m^3 Higher η_{RT} than TCES Similar techno-economics to LAES	Compression heat not recycled Discharge at 850°C
Park *et al.* 2020 [105]	Co-designed LAES-LNG	TD, ECO	Independent operation of LAES and LNG through cold storage	85.1	2680 $/kW	0.37 kW/kg LNG, high capacity 8.7-11.7% peak power contribution in the case study	Efficiency depends on assumptions on LNG use
Qi *et al.* 2020 [94]	Co-designed LAES-LNG + ORC	TD, ECO	Flexible operation with target efficiency or power output	129.2	N.A.	85.7-94.8 kJ/kg LNG Adjustable power output to support grid	Compression heat not recycled
Wang *et al.* 2020 [93]	LAES + O_2 production + heating	TD, ECO	Multifunctional LAES Adaptability to operating scenario	39.0	3000 $/MW	Economic value 114-153% higher despite lower efficiency 45.7% hot recycle for heating	1-D, transient absorber bed model for ASU
Gao *et al.* 2020 [106]	Trigenerative LAES	TD, ECO	Multi-vector output Support to external thermal load	45.7	PBT about 5 years	Techno and financial feasibility Case-dependent results based on the integration	Seasonal operating modes Cooling from turbine outlet
Cetin *et al.* 2020 [107]	Co-designed LAES-geothermal + ORC	TD	Reduced geothermal losses Fully dispatchable plant Use of evaporation cold	28.4	N.A.	Higher geothermal temperature decreases efficiency	Compression heat not recycled No cold recycle
He *et al.* 2020 [108]	LAES + LNG regassification + ORC + cooling	TD	Cascade cold recycle Cooling capability	142.0	N.A.	217 kW of cooling alongside 103.3 kW power output Higher efficiency by 19 points	ORC fluid composition is optimised for maximum power output
Nabat *et al.* 2020 [109]	LAES + ORC + thermoelectric device + DHW	TD, ECO	Diversified output Limited losses	61.1	3.91 years PBT, 18.6 M$ life revenues	Besides 96 MW electricity, 2.5 kg/s DHW produced 104 MJ/m3 density	Charge pressure is critical, optimal value at 146 MPa
She *et al.* 2020 [110]	LAES + absorption chiller + heating + DHW	TD	Full use of compression heat Multi-vector output	55.0	N.A.	Low charge pressure increases available heat Energy efficiency up to 76%	Small scale system: 1 MW and 8h

Abbreviations: LA: liquid air, AL: air liquefaction, TCES: Thermochemical energy storage, DHW: domestic hot water, TD: thermodynamic, ECO: economic, SQP: sequential quadratic programming, GA: genetic algorithm, SRQPD: successive reduced quadratic programming, opt: optimisation.

Concerning LAES discharge cycle, external heat sources can be used to raise turbine inlet temperature, augmenting LAES power output and electric efficiency. It is for example the case of waste heat from nuclear [91,113], or concentrated solar power plants [96]. However, heat storage might be required to ensure availability of the external source, for example in the latter case [101,114]. As an alternative to external heat sources, a portion of 20-40% compression heat cannot be used by standalone plants [46] and is readily available through hot recycle. To exploit this resource, an increased number of expansion stages could be used [86], or additional bottoming cycles [86]. ORC or NH_3-H_2O

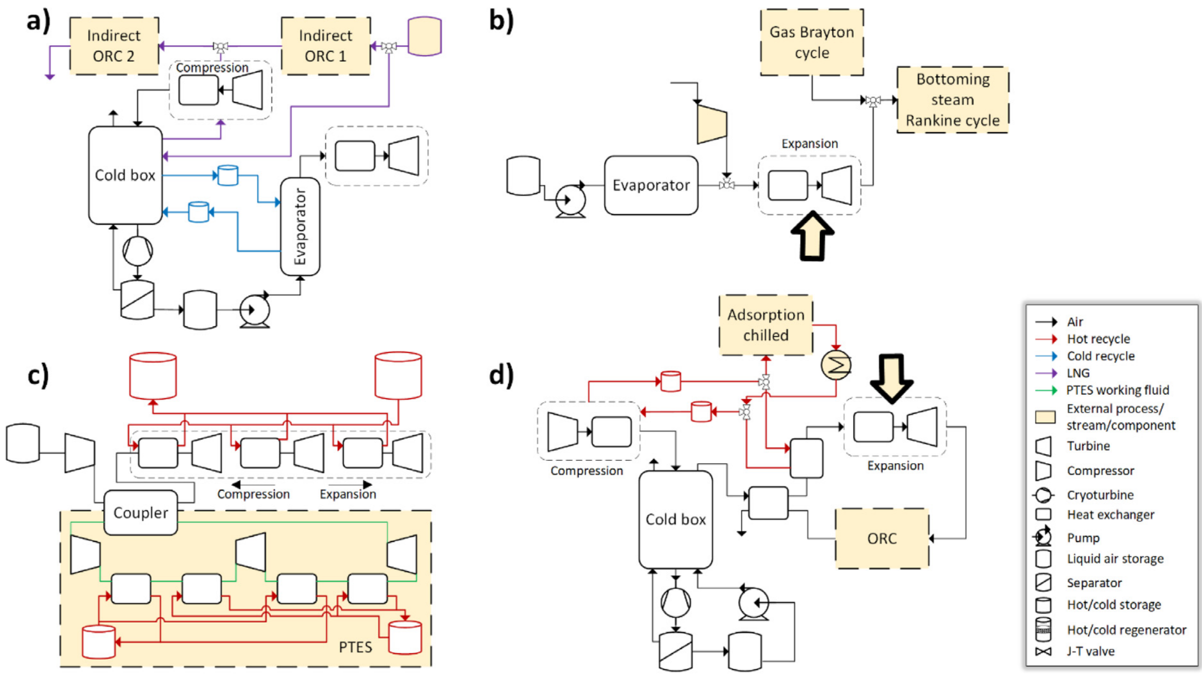

Fig. 12. Examples of hybrid LAES layouts, adapted from literature. a) LNG regasification + LAES [94], b) gas turbine with LAES extension [95], c) LAES-PTES concept [82], d) trigenerative LAES with ORC and combustion chamber [37].

Kalina power cycles – which better match the temperature glide during air evaporation – are the chosen solutions, leading to 9-12% electric efficiency improvement [54,81].

LAES performance boost can also be achieved through fuel combustion upstream of the turbines, which allows reaching inlet temperatures above 850 K [87,90]. LAES power generation and specific work output greatly increase, from 350-500 kJ per unit mass of liquid air, to above 900 kJ/kg. However, this comes at the expenses of a process relying on fossil fuels and wasting the produced compression heat.

4.2. Hybridization of LAES through process co-designing

Further hybrid LAES concepts have been proposed by co-designing systems with LAES and another selected energy process. This is the case, for example, of the hybrid LAES-geothermal system proposed by Cetin *et al.* [103], whereby the liquid water fraction after flashing is used for liquid air reheating before being re-injected into the soil. Altogether, the hybrid concept represents a fully dispatchable plant, enabling full exploitation of the geothermal resource (efficiency raises to 24%, from the 5-20% of conventional geothermal plants). Follow-up work optimised flashing pressure and added a propane ORC to further boost efficiency by 4 percentage points [107]. Benefits from a fully-coupled LAES-LNG system can go beyond the use of LNG cold energy to support air liquefaction. As a notable example, Lee *et al.* [66] designed a hybrid system suitable for LNG regasification terminals [99], where LNG expansion alone provides both the power and cooling effect necessary to achieve 100% liquefaction in a slightly pressurised vessel [92], yielding remarkable values of electrical efficiency.

Further hybrid concepts were also proposed to overcome certain technical limitations or bottlenecks of LAES. For example, Farres-Antunez *et al.* proposed a hybrid LAES-PTES plant, where the LAES evaporator is replaced by a coupling heat exchanger and there is no need for cold TES [82]. Such concept can even achieve full air liquefaction by subcooling. Elsewhere, a hybrid LAES-battery system has been proposed to participate in grid balancing services with response times of few seconds, which would otherwise be not feasible given the typical ramp rates for thermo-mechanical storage technologies [87]. Alternatively, a hybrid LAES-CAES plant was proposed to alleviate capacity and geographical constraints of compressed air energy storage [98,115]. Such concept was deemed as suitable for overused/undersized CAES plants, where the large wrong-time energy availability makes low conversion efficiencies between compressed and liquid air less of a concert.

4.3. Additional hybrid LAES functionalities

LAES hybridisation has also been considered as a route to enhance the performance of external processes through added functionalities beyond electrical storage. For example, in the context of traditional baseload plants or peakers, air from LAES discharge can participate in combustion and expansion processes, allowing to reduce turbine ratings by half [38], increase energy conversion efficiency compared with common gas turbines [116] and modulate power output thus increasing daily profit by 3.8-4.1% thanks to flexible plant operation at low marginal cost [117]. Additionally, liquid air storage was also proposed for oxy-fuel combustion plants to enable heat integration [118] and/or cryogenic CO_2 capture [119]. Integration of LAES with biomethane liquefaction plant has been recently proposed [120]. The study demonstrated the proposed concept has the potential to reduce compression duty by 38% (due to the cooling effect by air evaporation), and partially cover it with the electricity generated by LAES.

The potential of LAES to provide, besides electricity, also heat and cold to external processes has been investigated in a number of recent publications. Compression heat can be used to satisfy external needs for heating and domestic hot water, while cooling demand can be met by either an additional absorption chiller [37,54,110] or, directly, from air evaporation [121]. A hybrid LAES-LNG process has also been proposed to produce cooling for a data centre, in a way that optimises the cascade use of LNG and air evaporation cold [108]. Finally, LAES coupling with an air separation unit has been proposed to provide peak electricity, pure oxygen and building heating [93]. Despite an electrical efficiency reduction to 39% for the joint process, the economic value from the extra services abates payback time to about 5.7 years for a 10 MW/80 MWh plant.

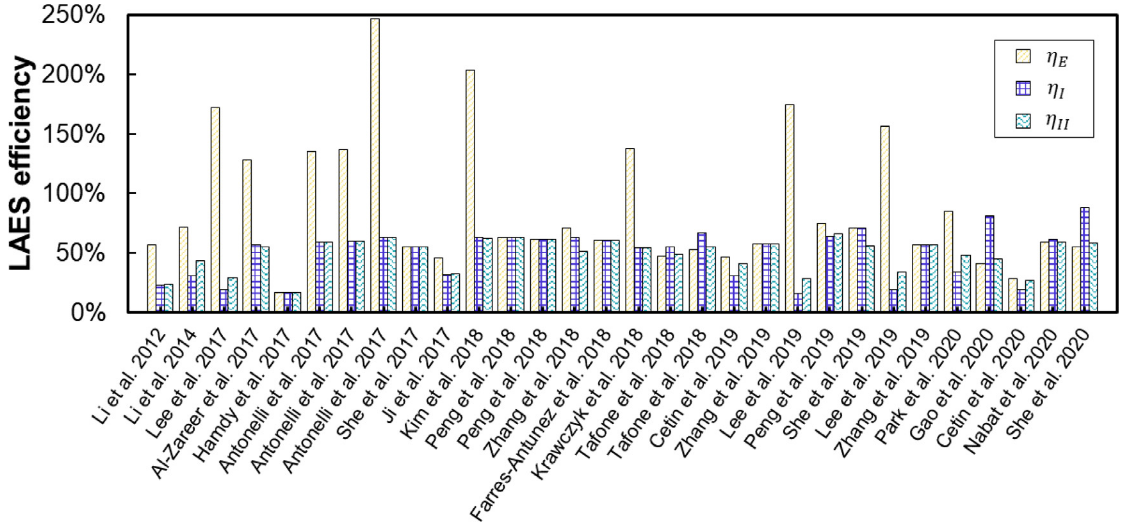

Fig. 13. Technical assessment of different hybrid LAES plants, based on the proposed performance metrics.

4.4. Techno-economic assessment

Fig. 13 presents the efficiency Fig.s from the proposed assessment methodology for hybrid LAES concepts. As compared to standalone cases, results show a much wider range of electrical efficiency, which, in cases of external heat or fuel input to LAES, can reach values above 100%. Two main routes have been investigated for enhancing electrical efficiency in hybrid plants: the addition of a combustion chamber and the integration of external LNG streams. The first greatly increases LAES specific work output, with no changes in the liquefaction cycle [90,122]; however, compression heat is lost, leading to lower energy and exergy efficiency values compared to other concepts. In addition, the combustion process also accounts for the highest contribution to plant exergy losses [22,37]. In the second approach, if the LNG stream can be considered "freely available" – as it is the case for all the papers focussing on this integration – η_E values are high and can surpass unity. However, from a thermodynamic perspective LNG represents an additional and highly valuable energy feed to LAES process – as typically available at -162°C. Therefore, the computed energy and exergy efficiency are between 16% and 63% and 29% and 62%, respectively. Hybrid concepts with LAES and solar thermal [96,101] show electrical efficiency between 56% and 47%, but low values of energy and exergy efficiency, both below 30%. Improvements through solar concentration and the use of compression heat in the process are necessary.

Based on exergy efficiency, our analysis reveals hybrid systems with additional organic power cycles achieve the best use of the internally recycled thermal streams. Values consistently around 55% for standalone plants rise to 62-63% for hybrid LAES-ORC. On the contrary, the highest energy efficiency occurs for hybrid LAES implementing trigeneration [37,54], with a remarkable 88% for the concept proposed by She *et al.* [110] which provides electricity, domestic hot water and space heating and cooling. Although from exergy point of view plant efficiency is not as high (different quality for different energy vectors), depending on the price to which heat and cold are sold, a trigenerative LAES can be economically advantageous over traditional plants.

Fig. 14 shows the direct comparison of standalone and hybrid LAES plants in the form of boxplots, where boxes (from 25th to 75th percentiles) and whiskers include 99.3% coverage of the sample data, and outliers are identified with a red cross. Overall, the efficiency metrics proposed in section 2.2.2 of this work are more informative of plant performance and allow to better characterise LAES technology. Electrical efficiency varies significantly for hybrid concepts, due to the external processes coupled with LAES system. On the contrary, energy and exergy efficiency show minimal variations around their average value, with exergy efficiency consistently sitting between 55 and 65% for all the concepts. Energy and exergy efficiency are indeed suited for cross-comparing the process conversion efficiency of alternative LAES concepts on a like for like basis. Misleading Fig.s of η_{RT} as reported in the literature (see Table 6) are originated by inconsistent definitions and/or assumptions such as "free stream" [99], which are avoided this way. By using three independent metrics, the current review rectifies this aspect and provides a consistent range of efficiency values for LAES.

Additionally, energy and exergy efficiency values show that, apart from full use of compression heat with LAES-ORC, the main reason to prefer hybrid to standalone LAES concepts relates only to the availability/use of external waste streams or additional functionalities from Section 4.3: in terms of exergy efficiency of the conversion processes, Fig. 14 shows no significant difference. Energy and exergy efficiency metrics are relevant for assessing plant design and identifying process improvement opportunities, which electrical (or roundtrip) efficiency alone fails to do. For example, in a hybrid LAES-geothermal plant, the electrical efficiency is 46.7% and comparable with standalone concepts. However, the computed exergy efficiency is rather low (41%), because of compression heat rejection and no recirculation of evaporation cold to increase liquefaction performance, showing further improvements in the LAES process are possible.

LAES investment cost for hybrid plants is presented in Fig. 15, in 2017€ units. Data mainly stem from the work of Hamdy *et al.* [42] – currently the only document merging most of the hybrid LAES concepts – and were complemented by additional cost Fig.s for hybrid LAES from other references. Fig. 15 shows that waste heat utilisation or combustion consistently lead to the lowest specific cost values, which are on the lower hand of the range for standalone plants (see Fig. 11). Also for hybrid solutions, more than 50% of costs belongs to power equipment [105] and waste heat recovery, despite showing a certain variability associated with temperature levels, allows to boost LAES power output at very limited marginal cost. In the case of combustion, costs are higher but compensated by the increase in power output: analysis by Li *et al.* [97] found the cost per peak energy generation for their hybrid LAES peaker to be comparable with NGCC and Oxy-NGCC plants.

In hybrid concepts, the addition of an ORC does not influence the investment cost for the overall plant, given the 2.2k€/kW marginal cost for the extra ORC is aligned with the estimates for LAES [123]. When operating over 300 cycles per year with off-peak and peak tariffs, the extra investment from ORC installation is recovered with an excellent 2.7 years payback time [46]. Concerning the LNG case, hybrid plant

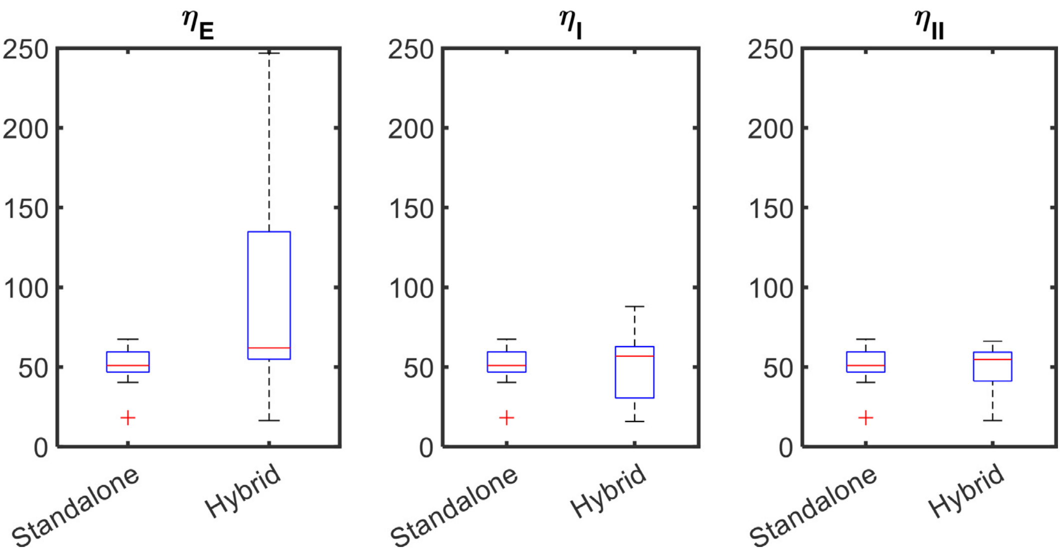

Fig. 14. Boxplot comparing standalone and hybrid LAES plants on the basis of the proposed performance metrics.

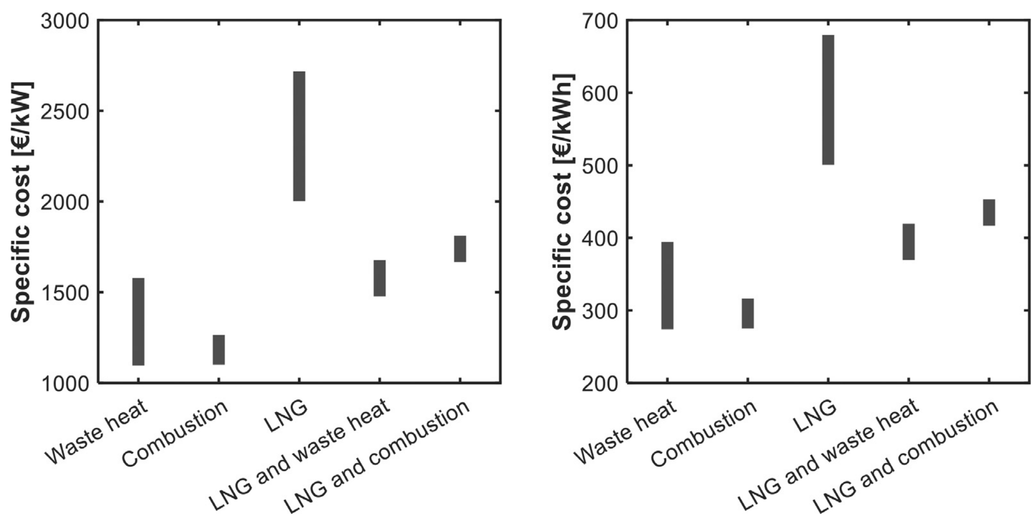

Fig. 15. Indicated values of specific investment cost for different hybrid LAES concepts.

prices are significantly higher, mostly due to the contribution of heat exchangers with large associated duties, in this case. Results from other studies report 2164 $/kW for the latest optimised system [94] with LNG and LAES and 2800 $/kW for the non optimised system including also an ORC [124]. Compression equipment and heat exchangers make up most of the investment cost here. Dealing with other hybrid concepts, projections for LAES-PTES costs are lower than the separate cost of the two technologies as the cold TES is avoided [82]. The hybrid CAES-LAES system was found to be financially advantageous only for charging time above 36h [125], but no investment Fig.s were provided.

5. LAES integration with the energy system

Literature findings from the previous sections confirm LAES technical performance and plant investment cost are overall well understood, but most studies only inform on the unit investment cost, without a detailed economic feasibility analysis. To realistically gauge LAES financial viability, it is essential to contextualise LAES techno-economic performance with the regulatory and energy market landscape in which it is required to operate. Therefore, this section addresses LAES integration with the energy system. Works are reviewed where, parallel to LAES plant, features of the broader energy system are included in the analysis. LAES operation is considered in these works and thus the role of LAES *within* the energy system is assessed. Two examples are provided in Fig. 16: in the work from Kalavani *et al.* [129], LAES is part of the detailed model for a microgrid, which captures the technical aspects of wind availability, curtailment and demand-supply matching; in [130], energy market participation of LAES is studied by electricity price signal and explicit modelling of the constraints associated with reserve service provision.

A summary of the studies on LAES integration with the energy system is provided in Table 7; despite some early investigations, most of the works (13 out of 20) were published after 2018 and focus on standalone plants (with external waste heat addition in a couple of cases [88,131]). The wide integration scope considered in these works results in different assessment criteria of LAES value, as different storage contributions are valued over different scales (e.g. local, regional, national); examples include RES penetration, grid independence, power stability and system security [132,133].

Levelised cost of storage (LCOS) – also referred to as LCOE in some publications – is defined as the total lifetime cost of an electricity storage technology divided by its cumulative delivered electricity, for a given interest rate (explicit formula can be found in [126] or [127]). Therefore, on top of investment cost, LCOS includes information on storage use and

Table 7
Summary of the reviewed studies dealing with energy system integration of LAES.

Reference	Type of integration	Methodology	Research questions	LAES plant	η_{RT}	Findings	Notes
Khani *et al.* 2015 [141]	EES – Ontario open retail electricity market	MILP optimal scheduling	Profitability, subsidy scheme, planning horizon	Standalone 57-100 MW	60%*	Not profitable unless subsidised, wrong price prediction hinders revenues	Arbitrage only LAES centric model
Zhang *et al.* 2015 [142]	EES + industrial gas production – ASU-PRU integration	MILP optimal scheduling	Integration benefits	Decoupled ASU-PRU 10 MW	70%*	10% relative savings, suitable for underutilised ASU	Arbitrage and reserve Robust optimisation No recycle PRU-ASU
Ahmad *et al.* 2016 [143]	EES + air conditioning from liquid N_2 - residential	Techno-economic assessment	Techno-economic viability of 5 process layouts	Only discharge 10 kW	N.A.	Profitable vs conventional HVAC	Not a LAES, small scale External use of high grade cold
Tafone *et al.* 2017 [144]	EES for chiller operation – cooling load provision	Techno-economic assessment	Profitability	Standalone	45%*	Profitability only for high price differentials and LAES efficiency	Parametric analysis Introductory assessment
Comodi *et al.* 2017 [145]	Cold TES	Multicriteria assessment	Comparison with other cold TES solutions	Standalone 1-21 MW	25-60%	Competitiveness at large scale	Based on ideal conversion parameter
Zamani-Gargari *et al.* 2018 [146]	EES – LAES and wind farm	Monte Carlo simulation	LAES contribution to system reliability	Standalone 5-10 MW	70%	LOLE and LOLP decrease linearly with more LAES	Technical aspects of grid support only
Xie *et al.* 2018 [88]	EES – UK energy market	Optimal dispatch algorithm + GA for independent sizing	Profitability of decoupled LAES	Standalone 50-250 MW	60%**	Extra revenues, large scales needed, waste heat boosts PBT from 25 to 5 years	Arbitrage + STOR
Wang *et al.* 2018 [136]	EES – multi-energy hub	MILP optimal scheduling	EES operation in realistic, multi-energy setting	Standalone 350 kW	60%	LAES smoothens load peaks	Simple LAES black box model Small scale
Kalavani *et al.* 2019 [129]	EES – ASU + PRU with wind farm	MINLP optimal scheduling	Local storage value in presence of DR schemes	Standalone 50 MW	70%	Revenues: +33%, cost of generation: -8%	No recycle PRU-ASU One day horizon
Mazzoni *et al.* 2019 [147]	EES + cold TES – LAES in microgrid	MIQP optimal scheduling	LAES comparison with battery	Standalone 300-2000 kWh	N.A.	Contribution to cooling supply, LAES convenient for large sizes	Functional dependence cooling-power output
Lin *et al.* 2019 [131]	EES – UK energy market	Optimal dispatch algorithm + GA for independent sizing	Expected NPV for different LAES sizes	Standalone 50-200 MW	60%**	Large scales needed, waste heat crucial, PBT from 40 to 10 years	Arbitrage only
Kalavani *et al.* 2019 [148]	EES – ASU + PRU with wind farm and microgrid	2-stage, stochastic optimal sizing and operation	Profitability and best independent sizing	Standalone Up to 10 MW	70%	15% overall cost reduction for 7 MW, 35 MWh best design	LAES enables RES uptake in local settings
Legrand *et al.* 2019 [57]	EES - Spanish power grid	Residual load analysis	LCOE in future scenarios with high PV penetration	Standalone	51.2%	LCOE is 150 €/MWh, energy is charged during the day, adaptability to generation mix	Ideal LAES efficiency Aggregated LAES capacity nationally
Georgiou *et al.* 2020 [135]	EES – European power grid	System-level unit commitment	LAES value for different penetrations, comparison with PTES	Standalone 12 MW, 50 MWh	55%	Storage value 2000 £/kW, decreasing for higher penetrations 5-15 GW required	Role of power/capacity ratio Contrast with other flexibility measures
Vecchi *et al.* 2020 [130]	EES - UK energy market	MILP optimal scheduling	Profitability, independent LAES sizing, ancillary services	Standalone 50-300 MW	60%***	Yearly revenues 20 k£/MW, small liquefiers and LAES below 2-3h recommended	Arbitrage + STOR + FR LAES thermodynamics included Multi-mode profitable but impacts on roundtrip
Gao *et al.* 2020 [106]	Trigenerative LAES – Regional scale	Techno-economic assessment	Technical-economic potential	Hybrid 2 MW	N.A.	Electrical efficiency 40-48%, LCOE 0.11$/kWh, dynamic payback period 4-6 years	Parametric analysis on plant layout Conversion efficiency varies with seasons

* Sensitivity analysis on the value.
** With waste heat recovery the value increases.
*** Rated value – it changes with operation.

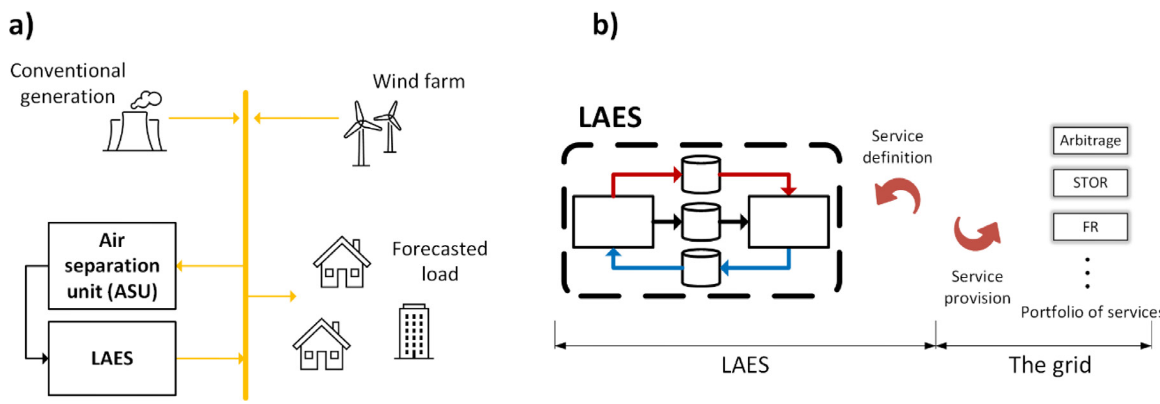

Fig. 16. Examples of works dealing with LAES integration in the energy system: a) adapted from [129]; b) adapted from [130].

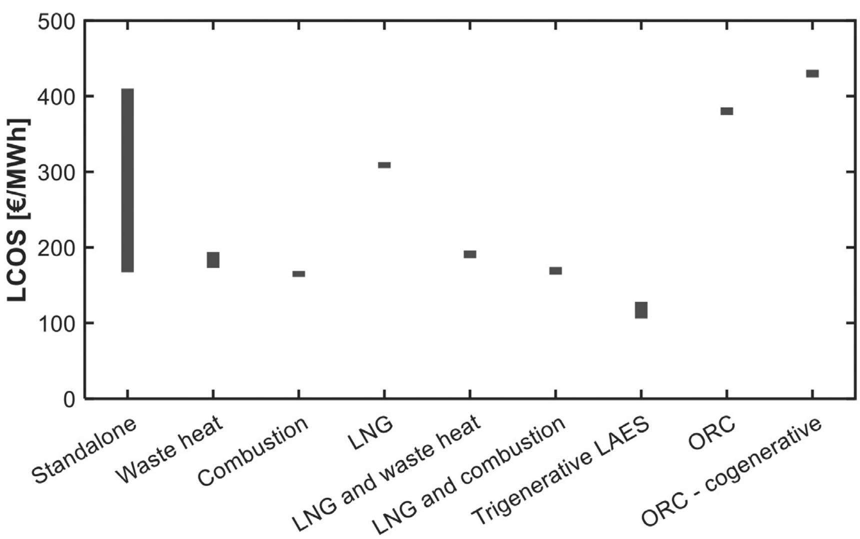

Fig. 17. Indicative LCOS for standalone and hybrid LAES concept.

represents a first approach to the financial assessment of storage integration. LCOS values have been quantified in the reviewed literature, as presented in Fig. 17, for standalone and hybrid LAES, ranging between 130 and 300 €/MWh in most of the cases [128]. Standalone LAES is addressed by more works, resulting in a larger distribution of results when compared to hybrid LAES. However, LCOS Fig.s suffer from additional uncertainty, mainly because of assumptions on full load hours, discount rate and electricity price [123].

Explicit optimisation of storage operation in realistic application scenarios allows dropping the inherent assumptions in LCOS. In this sense, most works reviewed investigate storage-only scheduling and dispatch. One single paper has so far addressed the key aspect of quantifying LAES value for a holistic power system setting, in a unit commitment framework for the European power system [135]. LAES emerged as an attractive option up to 5-10 GW of installed capacity in Northern Europe and 10-15 GW in the South. With such uptake, the identified cost target was 930-1800 £/kW (225-435 £/kWh), which is consistent with the Fig.s reported for standalone and most hybrid LAES (except coupled LAES-LNG plants) at the current development stage (see Sections 3.4 and 4.4). Most notably, such study provides a perspective on LAES coordination with other generation, storage and transmission technologies, as well as grid flexibility measures such as demand-side response; more work is needed in this direction.

Additionally, LAES is often treated as an input-output black-box model with constant roundtrip efficiency [123,136]. η_{RT} values from Table 7 are significantly spread across different works and, more importantly, not always aligned with the technical findings from Sections 3.4 and 4.4. Such an approach fails to distinguish LAES from other storage technologies and recent studies have shown how changes in the power output can generate off-design operation [137] and variations up to 30% on LAES efficiency [138]. A storage model formulation to account for LAES thermodynamic characteristics has also been proposed by the same authors [130], showing improved results accuracy and feasible scheduling. Similar studies for CAES [139,140] also proved the relevance of accurate storage modelling for financial assessment of storage integration, especially when reserve services are part of the operation strategy. On top of efficiency variations, other characteristics such as ramp rates or feasible regions for LAES power modulation are disregarded in most work, yet they represent crucial technical constraints from a system integration perspective and across the different applications considered for LAES in the literature.

5.1. *Applications considered for LAES in the literature*

As a developing storage technology, no single application is yet designated for LAES operation. Integration studies have so far focussed on the balancing services which suit LAES specifics and whose technical feasibility has been in some cases trialled on the demonstration plants. Applications considered range from energy balancing in the day-ahead market, to power balancing and reserve provision in the intra-day market, to the smart use of LAES as a multi-vector provider. Each one comes with associated challenges and opportunities which are described in the next application-specific subsections, as a conclusion to the discussion on LAES integration.

A transversal theme to many applications is the independent sizing of charge, discharge and storage sections, which allows tailoring LAES to the specific integration setting and operation strategy envisioned and fosters business cases [88,131]. In case of large PV penetration and over-production in the central hours of the day, Legrand *et al.* [57] showed 3-hours charge and long discharge plants are preferable to common solutions (e.g. involving 8-hours charge overnight [103]); this reduced LCOE from 250 to 150 €/MWh. Similarly, storage capacities above 4-5 h can be cost-effective when LAES is used for load-shifting (with daily or weekly scheduling [133]), while small liquefiers and no more than 2-3 hours of storage capacity are recommended for the provision of reserve services involving high power commitment and short sustained periods [130]. Compared to incumbent storage technologies, this is a unique feature of LAES: batteries and PHES are constrained to the same charge/discharge rate [7], while CAES capacity is limited by the volume of the cavern [134]. Optimal plant sizing for the considered application may be attained directly, for example through genetic algorithm [88] or indirectly, through sensitivity analysis [130].

5.1.1. Energy balancing in the day-ahead market

As large storage, LAES can be operated to shift loads from periods of high to low demand; with such strategy, revenues come from buying cheap off-peak electricity to be sold at peak prices, in the day-ahead market (i.e. arbitrage). However, studies on LAES integration prove profit from arbitrage is not enough for financial viability. In the absence of subsidies [141] or waste heat integration [131], LAES cannot return the investment during the expected lifetime. Similar results were already described for other grid-scale storage technologies [150] or even batteries [149] and contrast with some over-optimistic economic results reviewed in Sections 3.4 and 4.4. Deceivingly high NPV and payback time often below 10 in these cases derive from idealised LAES operation, which stresses the need for including energy system constraints and dynamics in integration studies.

Peak-to-valley price ratio between 3.2 and 4.4 is indicated in [141], to ensure positive LAES returns in the day-ahead market. These values are currently too high, even if large RES uptake could lead to price modifications in the future [151]. Therefore, arbitrage alone hardly makes the financial case for LAES, unless efficiency is improved, or costs are reduced, compared to the Fig.s from sections 3.4 and 4.4. Long scheduling horizons are also accessible and may contribute to making arbitrage more economically viable [131,133], despite a higher uncertainty of electricity price predictions.

5.1.2. Reserve provision and additional grid services from LAES

In the reviewed studies on LAES integration, opportunities arise from the participation of LAES beyond the day-ahead market, to intra-day markets and reserve services provision. Both applications necessitate a fast power delivery and rapid output adjustment when requested. However experimental evidence from the pilot plant is promising: the indicated 100 s response time for standalone LAES is within the technical requirements for most reserve services and plant ramp rates ensured 99% compliance with the PJM test for load-following operation with 5 min ramps [44]. Even at hundreds of MW scales, gas turbine manufacturer General Electric[2] and Siemens[3] indicate typical ramp-up times for axial machines between 20 and 50 MW/min. Hybridization with flywheels, batteries or capacitors would further extend the number of accessible services to the area of frequency regulation [87]. Integration studies accounting for reserve participation show 10% to 30% higher revenue, depending on plant size, from provision of short term operating reserve (STOR) in the UK market [88]. Fast reserve was also considered, making the financial case for LAES with about 20 k£/MW of yearly revenues [130]. Clearly, the participation in a portfolio of balancing services in these cases introduces the need for prioritisation [152].

Beyond power system stability, additional benefits from LAES can also be of interest, depending on the scale of the integration considered. For instance, in a district-level case study in Ontario, the increase in reserve margin from 17.7 to 21.4% was used by Park *et al.* [153] as an indicator of a more stable electricity supply thanks to the operation of a hybrid LAES-LNG plant. At distribution or microgrid level, LAES technical benefits and financial opportunities may come from increased penetration of renewables, lower levels of electricity import and dependence on the grid [129]. Common resilience indicators such as loss of load expectation (LOLE) and loss of load probability (LOLP) were used for this assessment and significantly improved, to 0.4 hours/year and 39.3 occurrences per year, respectively [146].

5.1.3. Beyond electricity: LAES as a multi-vector storage asset

As discussed in section 3.1 and 3.2, LAES charging and discharging processes involve the generation and use of heat and cold, which can be supplied externally as hot and cold streams, on top of electricity. This feature opens up some interesting opportunities for energy management and, from the integration standpoint, for using both standalone and hybrid LAES as vector-coupling assets. Works so far explored vector-coupling potential for other thermo-mechanical technologies such as CAES [154–156] or PTES [157], for example through the CHESTER project [158]. However, the study of multi-energy LAES operation is currently in its infancy.

Concerning cold supply, Mazzoni *et al.* [147] showed the poly-generative operation of LAES over electricity and cooling can make it more economically attractive than a battery, for a microgrid application. Comodi *et al.* [145] claimed LAES could be an economically viable option for cold storage and supply above 500 MWh. LAES integration with refrigerated warehouses is also currently under investigation by the CryoHub consortium [20,159]. Similarly for heating, compression heat utilisation is the focus of several technical investigations, but little has been done in the direction of LAES integration. A co-generative LAES might operate with reduced electrical efficiency, but still be economically worth when heat is sold above a threshold price [154]. Indeed, a study by Wang *et al.* [93] showed that about 10% extra revenues can be stacked up to the electricity sales that way, decreasing plant payback time. A trigenerative configuration of LAES may even supply combined heating, electricity and cooling. An integration assessment conducted for this configuration on 5 Chinese cities and showed a payback period within 5 and 7 years [106].

6. Conclusions and outlook

Given the high energy density, layout flexibility and absence of geographical constraints, liquid air energy storage (LAES) is a very promising thermo-mechanical storage solution, currently on the verge of industrial deployment. With the aim of cementing the understanding around LAES, the current review focussed on: i) harmonising research findings that emerged from different working methodologies and plant concepts, ii) discussing the opportunities for LAES coupling with other processes and iii) highlighting the current research gaps and the promising trends for LAES integration in the energy system. More than 120 publications have been reviewed and presented according to three main areas: standalone LAES, LAES hybridisation with external processes and/or energy sources, LAES integration in the wider energy system. Key outcomes are summarised in the following subsections.

6.1. State-of-the-art

For standalone LAES, energy and exergy efficiencies are between 50% and 60%, while investment cost ranges from 1.3 to 2.2 k€/kW (300-600 €/kWh). Such economic values are on the high end of the Fig.s for most grid-scale storage [160]. Efficient cold and hot recycle are crucial

[2] https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas-power-systems-product-catalog-2019.pdf

[3] https://assets.new.siemens.com/siemens/assets/public.1551272853.5001be9f0e51e56dbb66dcf0c0130538bf5722cd.gas-turbines-siemens-int.pdf

Table 8
SWOT analysis of future energy system integration pathways for LAES.

Pathway	Strengths	Weaknesses	Opportunities	Threats	Refs
Multi-market EES	Inexpensive Higher participation to grid stability	Off-design Exclusive services	High revenue, low risk Business cases Hybrid concepts	Market regulation needed Response times	[88,130,132,138]
Retrofit to existing systems (e.g. power plants, ASU)	Power modulation Low marginal cost Many functionalities	Reduced operation as EES	CO_2 capture Underutilised ASU Oxy-fuel combustion	System complexity Modifications to the existing plant	[87,89,117,132,148]
EES + waste heat/cold recovery	Higher efficiency Larger power output Lower system losses	Resource availability Variable operation	Flexible operation Co-designed systems Low-carbon clusters	Co-location needed Scheduling Case-dependent	[18,67,80,102,103]
Multi-vector – EES + heating and/or cooling	Unique of thermo-mechanical storage TES capability Vector-coupling	Lower electrical efficiency Competing nature of outputs	Microgrid and local integrated systems Low-carbon clusters Waste heat/cold recovery Rising cooling demand	Output scheduling Missing assessments Temperature levels System complexity	[37,106,121,123,144,145,147,159,161]

to ensure the intended plant performance and, while all the high-grade cold from air evaporation should support air liquefaction, more compression heat is produced than internally required. Hybrid LAES can make full use of such excess heat or exploit external fuels and thermal streams to improve LAES performance. More than 15 hybrid layouts have been proposed, the most common including bottoming ORC, LAES coupled with LNG terminals, fuel combustion or use of waste heat from neighbouring processes. Hybrid LAES can achieve exergy efficiency up to 65% and electric efficiency above 1, meaning greater potential for grid balancing. Techno-economic assessments show LAES hybridisation can foster immediate deployment, but the present analysis highlights its value as a complement, not a substitute, for the internal recycle of available hot and cold streams. Two projects for 50 MW standalone LAES have been announced by Highview Power. They will be commissioned in the next years and will represent the first grid-connected LAES plants worldwide.

6.2. LAES integration pathways

Energy system integration represents a crucial step towards LAES commercial deployment, which arguably has not received sufficient attention so far. The key integration pathways for LAES, as emerged from literature findings, are reported in Table 8, in the form of a SWOT analysis.

Concerning grid applications, electricity balancing in the day-ahead market must be complemented by intra-day balancing and/or provision of reserve services to result in favourable business cases for LAES. Suitable market regulation and prioritisation schemes for such services will greatly boost LAES value as an energy storage asset. At a local scale, support of higher RES penetrations and enhanced reliability should be the primary applications of LAES. Additionally, LAES could be used to retrofit existing power plants or underutilised ASU, adding energy storage and output modulation capabilities, alongside other functionalities such as cryogenic CO_2 capture.

Besides traditional electricity storage operation, the smart use of LAES for waste heat/cold recovery and multi-vector provision is only marginally addressed in the literature. Waste heat integration at 150-200°C can yield immediate economic feasibility for LAES, on top of reducing system losses and the same be said for external cold recovery. Flexible supply of heating, cooling and electricity from LAES may also become relevant for an increasing number of sites – particularly cooling – due to the rise in cooling needs and the associated price. Given the emphasis on decarbonising heating, cooling and power sectors, multi-vector operation is potentially the most interesting integration pathway to be pursued with LAES and more research is needed in this direction.

6.3. Research gaps and future perspectives

To conclude, we highlighted the following research gaps and recommend these areas to be explored for further advancing the research on LAES:

- **A comparative assessment of LAES with other storage solutions is lacking**: comprehensive system-level simulations such as that in [135] are needed. Analysis should include LAES with other storage and generation technologies, as well as flexibility measures, and be free from assumptions on storage operation or duty cycle. Results cross-comparison should be used to highlight strengths and weaknesses of LAES with respect to the alternatives
- **Oversimplified LAES models neglect important technological constraints for system integration**: advanced storage models including off-design performance, technical limitations to LAES operation such as feasible power modulation regions, ramp rates and other non-idealities are necessary, along with frameworks to include these LAES models in system-level assessment. This is particularly relevant for the large variability of LAES setpoint in cases of hybrid plants, multi-service and multi-energy provision
- **A limited number of integration studies are available, which are highly case-dependent**: more studies should focus on: i) future scenarios with high levels of RES penetration, electrification etc. ii) linking outcomes to the specific integration scale considered, iii) quantifying opportunities and barriers for LAES participation to fast-response reserve services in various electricity markets and iv) comparing hybrid to standalone LAES financial viability in realistic application cases
- **Clear strategies to a full use LAES potential above electricity storage are missing:** more case-study assessments should focus on waste heat/cold recovery from LAES, LAES vector-coupling operation or external provision of added functionalities. Initial evidence discussed in section 6 show that, specifically in low-carbon districts with increasing sector integration, a vision of LAES beyond electricity storage could open up several deployment opportunities.

Further research on the aforementioned topics will be key to identify the future value of LAES and inform stakeholders on the extent to which LAES uptake can contribute to meeting future grid decarbonisation targets.

Acknowledgments

Dr Adriano Sciacovelli acknowledges the financial support from the UK Supergen Energy Network Hub (EP/S00078X/1). Andrea Vecchi acknowledges the Priestley Joint PhD Scholarship from University of Birmingham (UK) and University of Melbourne (Australia).

Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.adapen.2021.100047.

References

[1] Masson-Delmotte V, Zhai P, Pörtner H-O, Roberts D, Skea J, Shukla PR, et al. *Global warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways*, in the context of strengthening the global response to the threat of climate change,. 2018.
[2] IEA IEA.. Technology Roadmap Energy storage; 2014.
[3] House C, Way N.*The world's water battery: Pumped hydropower storage and the clean energy transition International Hydropower Association*. n.d.
[4] Steinmann W-D. Thermo-mechanical concepts for bulk energy storage. Renew Sustain Energy Rev 2017;75:205–19. doi:10.1016/j.rser.2016.10.065.
[5] Castillo A, Gayme DF. Grid-scale energy storage applications in renewable energy integration: A survey. Energy Convers Manag 2014;87:885–94. doi:10.1016/j.enconman.2014.07.063.
[6] Luo X, Wang J, Dooner M, Clarke J. Overview of current development in electrical energy storage technologies and the application potential in power system operation. Appl Energy 2015;137:511–36. doi:10.1016/j.apenergy.2014.09.081.
[7] Chen H, Cong TN, Yang W, Tan C, Li Y, Ding Y. Progress in electrical energy storage system: a critical review. Prog Nat Sci 2009;19:291–312. doi:10.1016/j.pnsc.2008.07.014.
[8] Olympios A, McTigue J, Farres Antunez P, Tafone A, Romagnoli A, Li Y, et al. Progress and prospects of thermo-mechanical energy storage – a critical review. Prog Energy 2021. doi:10.1088/2516-1083/abdbba.
[9] Ding Y, Tong L, Zhang P, Li Y, Radcliffe J, Wang L. Chapter 9 - Liquid Air Energy Storage. Elsevier Inc; 2016. doi:101016/B978-0-12-803440-8/00009-9.
[10] BOC. Guidance on the safe operation of vacuum insulated storage tanks. VIEs and VITs. n.d.
[11] Wang S, Xue X, Zhang X, Guo J, Zhou Y, Wang J. The application of cryogens in liquid fluid energy storage systems. Phys Procedia 2015;67:732. doi:10.1016/j.phpro.2015.06.123.
[12] Smith EM. Storage of electrical energy using supercritical liquid air. Proc Inst Mech Eng 1977;191:289–98.
[13] Kishimoto K, Hasegawa K, Asano T. Development of generator of liquid air storage energy system. Mitsubishi Heavy Ind Ltd Tech Rev 1998:117–20.
[14] Araki H, Nakabaru M, Chino K. Simulation of heat transfer in the cool storage unit of a liquid-air energy storage system. Heat Transf - Asian Res 2002;31:284–96. doi:10.1002/htj.10035.
[15] Chino K, Araki H. Evaluation of energy storage method using liquid air. Chem Pharm Bull 2000;29:347–57.
[16] Morgan RE. Liquid air energy storage – from theory to demonstration. Int J Environ Stud 2016:460–80. doi:10.1080/00207233.2016.1189741.
[17] Chen H, Ding Y, Peters T, Berger F.*A method of storing energy and a cryogenic energy storage system*. WO 2007/096656, 2007.
[18] Peng X, She X, Li C, Luo Y, Zhang T, Li Y, et al. Liquid air energy storage flexibly coupled with LNG regasification for improving air liquefaction. Appl Energy 2019;250:1190–201. doi:10.1016/j.apenergy.2019.05.040.
[19] Highview Enterprises Ltd.*Highview power storage*. http://www.highview-power.com/ n.d.
[20] CryoHub - Cryogenic*Energy Storage for Renewable Refrigeration and Power Supply* n.d. https://cryohub.eu/en-gb/(accessed September 14, 2020).
[21] IES, ECES.*Annex 36*- Carnot Batteries n.d. https://iea-eces.org/annex-36/(accessed November 13, 2020).
[22] Dutta R, Ghosh P, Chowdhury K.*Process configuration of Liquid-nitrogen Energy Storage System (LESS) for maximum turnaround efficiency*2017. doi:10.1016/j.cryogenics.2017.10.003.
[23] Tafone A, Romagnoli A, Borri E, Comodi G. New parametric performance maps for a novel sizing and selection methodology of a liquid air energy storage system. Appl Energy 2019;250:1641–56. doi:10.1016/j.apenergy.2019.04.171.
[24] Yu Q, Song W, Al-Duri B, Zhang Y, Xie D, Ding Y, et al. Theoretical analysis for heat exchange performance of transcritical nitrogen evaporator used for liquid air energy. storage 2018. doi:10.1016/j.applthermaleng.2018.06.028.
[25] Liu Z, Yu H, Gundersen T. Optimization of Liquid Air Energy Storage (LAES) using a Genetic Algorithm (GA, 48. Elsevier Masson SAS; 2020. doi:10.1016/B978-0-12-823377-1.50162-2.
[26] Chai L, Liu J, Wang L, Yue L, Yang L, Sheng Y, et al. Cryogenic energy storage characteristics of a packed bed at different pressures. Appl Therm Eng 2014;63:439–46. doi:10.1016/j.applthermaleng.2013.11.030.
[27] Energy Innovation Zone - Tyseley Energy Park n.d. https://www.tyseleyenergy.co.uk/energy-innovation-zone/(accessed June 20, 2020).
[28] Akhurst M, Atkins A, Uk R, Bruges R, Cooper S, Consulting S, et al. *Liquid Air in the energy and transport systems*. 2013.
[29] Lim Y, Al-Atabi M, Williams RA. Liquid air as an energy storage: a review. J Eng Sci Technol 2016;11:496–515.
[30] Damak C, Leducq D, Hoang HM, Negro D, Delahaye A. Liquid Air Energy Storage (LAES) as a large-scale storage technology for renewable energy integration- A review of investigation studies and near perspectives of LAES. Int J Refrig 2020;110:208–18. doi:10.1016/j.ijrefrig.2019.11.009.
[31] Borri E, Tafone A, Zsembinszki G, Comodi G, Romagnoli A, Cabeza LF. Recent trends on liquid air energy storage : a bibliometric analysis. Appl Sci 2020:1–19.
[32] *Scopus preview - Scopus - Welcome to Scopus*n.d. https://www.scopus.com/(accessed September 8, 2020).
[33] Web of Science [v.5.35] - *Web of Science Core Collection Basic Search*n.d. http://apps.webofknowledge.com/WOS_GeneralSearch_input.do?product=WOS&search_mode=GeneralSearch&SID=D1OffWvCphaKWKa81i5&preferencesSaved= (accessed September 8, 2020).
[34] Wojcieszak P, Poliński J, Chorowski M.*Investigation of a working fluid for cryogenic energy storage systems Related content An overview of potential benefits and limitations of Compressed Air Energy Storage in abandoned coal mines Marcin Lutyski-Performance analysis of liquid air energy stora*2017. doi:10.1088/1757-899X/278/1/012069.
[35] Guo J, Cai L, Chen J, Zhou Y. Performance optimization and comparison of pumped thermal and pumped cryogenic electricity storage systems. Energy 2016;106:260–9. doi:10.1016/J.ENERGY.2016.03.053.
[36] Osorio JD, Panwar M, Rivera-Alvarez A, Chryssostomidis C, Hovsapian R, Mohanpurkar M, et al. *Enabling thermal efficiency improvement and waste heat recovery using liquid air harnessed from offshore renewable energy sources2020*. doi:10.1016/j.apenergy.2020.115351.
[37] Al-Zareer M, Dincer I, Rosen MA. Analysis and assessment of novel liquid air energy storage system with district heating and cooling capabilities. Energy 2017;141:792–802. doi:10.1016/j.energy.2017.09.094.
[38] Li Y, Jin Y, Chen H, Tan C, Ding Y. An integrated system for thermal power generation, electrical energy storage and CO2 capture. Int J Energy Res 2011;35:1158–67. doi:10.1002/er.1753.
[39] Guizzi GL, Manno M, Tolomei LM, Vitali RM, Leo Guizzi G, Manno M, et al. Thermodynamic analysis of a liquid air energy storage system. Energy 2015;93:1639–47. doi:10.1016/j.energy.2015.10.030.
[40] Morgan R, Gibson E, Brett Bsc G.*An analysis of a large-scale liquid air energy storage system*n.d. doi:10.1680/ener.14.00038.
[41] Hamdy S, Morosuk T, Tsatsaronis G. Exergoeconomic optimization of an adiabatic cryogenics-based energy storage system. Energy 2019;183:812–24. doi:10.1016/j.energy.2019.06.176.
[42] Hamdy S, Morosuk T, Tsatsaronis G. Exergetic and economic assessment of integrated cryogenic energy storage systems. Cryogenics (Guildf) 2019;99:39–50. doi:10.1016/j.cryogenics.2019.02.009.
[43] Georgiou S, Shah N, Markides CN. A thermo-economic analysis and comparison of pumped-thermal and liquid-air electricity storage systems. Appl Energy 2018;226:1119–33. doi:10.1016/j.apenergy.2018.04.128.
[44] Morgan R, Nelmes S, Gibson E, Brett G.*Liquid air energy storage - Analysis and first results from a pilot scale demonstration plant*2015. doi:10.1016/j.apenergy.2014.07.109.
[45] Sciacovelli A, Smith D, Navarro MEE, Vecchi A, Peng X, Li Y, et al. Performance analysis and detailed experimental results of the first liquid air energy storage plant in the world. J Energy Resour Technol Trans ASME 2018;140. doi:10.1115/1.4038378.
[46] She X, Peng X, Nie B, Leng G, Zhang X, Weng L, et al. Enhancement of round trip efficiency of liquid air energy storage through effective utilization of heat of compression. Appl Energy 2017;206:1632–42. doi:10.1016/j.apenergy.2017.09.102.
[47] Xue XD, Wang SX, Zhang XL, Cui C, Chen LB, Zhou Y, et al. Thermodynamic analysis of a novel liquid air energy storage system. Phys Procedia 2015;67:733–8. doi:10.1016/j.phpro.2015.06.124.
[48] Guo H, Xu Y, Chen H, Zhou X. Thermodynamic characteristics of a novel supercritical compressed air energy storage system. Energy Convers Manag 2016;115:167–77. doi:10.1016/j.enconman.2016.01.051.
[49] Hamdy S, Morosuk T, Tsatsaronis G. Cryogenics-based energy storage: Evaluation of cold exergy recovery cycles. Energy 2017;138:1069–80. doi:10.1016/j.energy.2017.07.118.
[50] Sciacovelli A, Vecchi A, Ding Y. Liquid air energy storage (LAES) with packed bed cold thermal storage – From component to system level performance through dynamic modelling. Appl Energy 2017;190:84–98. doi:10.1016/j.apenergy.2016.12.118.
[51] Xie Y, Xue X, Xie Y, Xue X. Thermodynamic Analysis on an Integrated Liquefied Air Energy Storage and Electricity Generation System. Energies 2018;11:2540. doi:10.3390/en11102540.
[52] Peng H, Shan X, Yang Y, Ling X. A study on performance of a liquid air energy storage system with packed bed units. Appl Energy 2018;211:126–35. doi:10.1016/j.apenergy.2017.11.045.
[53] Peng X, She X, Cong L, Zhang T, Li C, Li Y, et al. Thermodynamic study on the effect of cold and heat recovery on performance of liquid air energy. storage 2018. doi:10.1016/j.apenergy.2018.03.151.
[54] Tafone A, Borri E, Comodi G, van den Broek M, Romagnoli A. Liquid air energy storage performance enhancement by means of organic rankine cycle and absorption chiller. Appl Energy 2018;228:1810–21. doi:10.1016/j.apenergy.2018.06.133.
[55] Kim J, Chang D. Pressurized cryogenic air energy storage for efficiency improvement of liquid air energy storage. Energy Procedia 2019;158:5086–91. doi:10.1016/j.egypro.2019.01.638.
[56] Lin X, Wang L, Xie N, Li G, Chen H. Thermodynamic analysis of the cascaded packed bed cryogenic storage based supercritical air energy storage system. Energy Procedia 2019;158:5079–85. doi:10.1016/j.egypro.2019.01.639.
[57] Legrand M, Rodríguez-Antón LM, Martinez-Arevalo C, Gutiérrez-Martín F. Integration of liquid air energy storage into the spanish power grid. Energy 2019;187:115965. doi:10.1016/j.energy.2019.115965.
[58] Guo L, Gao Z, Ji W, Xu H, Chen L, Wang J. Thermodynamics and economics of different asymmetric cold energy transfer in a liquid air energy storage system. Energy Technol 2020;1901487:1–11. doi:10.1002/ente.201901487.

[59] Timmerhaus KD.*Cryogenic Process Engineering*. 2004. doi:10.1016/b0-12-227410-5/00156-3.
[60] Castle WF. Air separation and liquefaction: recent developments and prospects for the beginning of the new millennium. Int J Refrig 2002;25:158–72. doi:10.1016/S0140-7007(01)00003-2.
[61] Bowdery T.*Heatric technical brochuren.d*.
[62] Popov D, Fikiin K, Stankov B, Alvarez G, Youbi-idrissi M, Damas A, et al. Cryogenic heat exchangers for process cooling and renewable energy storage: a review. Appl Therm Eng 2019;153:275–90. doi:10.1016/j.applthermaleng.2019.02.106.
[63] Hamdy S, Moser F, Morosuk T, Tsatsaronis G. Exergy-based and economic evaluation of liquefaction processes for cryogenics energy storage. Energies 2019;12. doi:10.3390/en12030493.
[64] Abdo RF, Pedro HTC, Koury RNN, Machado L, Coimbra CFM, Porto MP.*Performance evaluation of various cryogenic energy storage systems*2015. doi:10.1016/j.energy.2015.08.008.
[65] Borri E, Tafone A, Romagnoli A, Comodi G. A preliminary study on the optimal configuration and operating range of a “microgrid scale” air liquefaction plant for Liquid Air Energy Storage. Energy Convers Manag 2017;143:275–85. doi:10.1016/j.enconman.2017.03.079.
[66] Lee I, Park J, Moon I. Conceptual design and exergy analysis of combined cryogenic energy storage and LNG regasification processes: Cold and power integration. Energy 2017;140:106–15. doi:10.1016/j.energy.2017.08.054.
[67] Lee I, Park J, You F, Moon I. A novel cryogenic energy storage system with LNG direct expansion regasification: design, energy optimization, and exergy analysis. Energy 2019;173:691–705. doi:10.1016/j.energy.2019.02.047.
[68] Zhang J, Meerman H, Benders R, Faaij A.*Comprehensive review of current natural gas liquefaction processes on technical and economic performance2019*. doi:10.1016/j.applthermaleng.2019.114736.
[69] Li Y, Chen H, Ding Y.*Fundamentals and applications of cryogen as a thermal energy carrier: A critical assessment*2010. doi:10.1016/j.ijthermalsci.2009.12.012.
[70] Brett G, Barnett M. The application of liquid air energy storage for large scale long duration solutions to grid balancing. EPJ Web Conf 2014;79:3002. doi:10.1051/epjconf/20137903002.
[71] Ameel B, T'joen C, De Kerpel K, De Jaeger P, Huisseune H, Belleghem V, et al. Thermodynamic analysis of energy storage with a liquid air Rankine cycle. Appl Therm Eng 2013;52:130–40. doi:10.1016/j.applthermaleng.2012.11.037.
[72] Krawczyk P, Szabłowski Ł, Badyda K, Karellas S, Kakaras E. Impact of selected parameters on the performance of adiabatic liquid air energy storage with steam module. J Power Technol 2016;4:238–44.
[73] Morgan R, Rota C, Pike-Wilson E, Gardhouse T, Quinn C. The Modelling and Experimental Validation of a Cryogenic Packed Bed Regenerator for Liquid Air Energy Storage Applications. Energies 2020;13:5155. doi:10.3390/en13195155.
[74] Hüttermann L, Span R. Influence of the heat capacity of the storage material on the efficiency of thermal regenerators in liquid air energy storage systems. Energy 2019;174:236–45. doi:10.1016/j.energy.2019.02.149.
[75] Dutta R, Sandilya P.*Experimental Investigations on Cold Recovery Efficiency of Packed-bed in Cryogenic Energy Storage System*n.d. doi:10.1088/1757-899X/755/1/012103.
[76] White AJ. Loss analysis of thermal reservoirs for electrical energy storage schemes. Appl Energy 2011;88:4150–9. doi:10.1016/j.apenergy.2011.04.030.
[77] She X, Li Y, Peng X, Ding Y. Theoretical analysis on performance enhancement of stand-alone liquid air energy storage from perspective of energy storage and heat transfer. Energy Procedia 2017;142:3498–504. doi:10.1016/j.egypro.2017.12.236.
[78] An B, Chen J, Deng Z, Zhang T, Wang J, Yang L, et al. Design and testing of a high performance liquid phase cold storage system for liquid air energy storage. Energy Convers Manag 2020;226. doi:10.1016/j.enconman.2020.113520.
[79] Hüttermann L, Span R, Maas P, Scherer V. Investigation of a liquid air energy storage (LAES) system with different cryogenic heat storage devices. Energy Procedia 2019;158:4410–15. doi:10.1016/j.egypro.2019.01.776.
[80] She X, Zhang T, Cong L, Peng X, Li C, Luo Y, et al. *Flexible integration of liquid air energy storage with liquefied natural gas regasification for power generation enhancement* ☆2019. doi:10.1016/j.apenergy.2019.113355.
[81] Zhang T, Zhang X, Xue X, Wang G, Mei S, Zhang T, et al. Thermodynamic Analysis of a Hybrid Power System Combining Kalina Cycle with Liquid Air Energy Storage. Entropy 2019;21:220. doi:10.3390/e21030220.
[82] Farres-Antunez P, Xue H, White AJ. Thermodynamic analysis and optimisation of a combined liquid air and pumped thermal energy storage cycle. J Energy Storage 2018;18:90–102. doi:10.1016/j.est.2018.04.016.
[83] Bernagozzi M, Panesar AS, Morgan R. Molten salt selection methodology for medium temperature liquid air energy storage application. Appl Energy 2019;248:500–11. doi:10.1016/j.apenergy.2019.04.136.
[84] Bernagozzi M, Panesar A, Morgan R.*Temperature-Tailored Molten Salts for Sustainable Energy Storage*. JOM n.d.;72. doi:10.1007/s11837-019-03916-8.
[85] Wu S, Zhou C, Doroodchi E, Moghtaderi B.*Techno-economic analysis of an integrated liquid air and thermochemical energy storage system2020*. doi:10.1016/j.enconman.2019.112341.
[86] She X, Peng X, Zhang T, Ding Y.*Configuration optimization of stand-alone Liquid Air Energy Storage for efficiency improvementn.d*. doi:10.1088/1757-899X/502/1/012015.
[87] Antonelli M, Barsali S, Desideri U, Giglioli R, Paganucci F, Pasini G. Liquid air energy storage: Potential and challenges of hybrid power plants. Appl Energy 2017;194:522–9. doi:10.1016/j.apenergy.2016.11.091.
[88] Xie C, Hong Y, Ding Y, Li Y, Radcliffe J.*An economic feasibility assessment of decoupled energy storage in the UK: With liquid air energy storage as a case* study 2018. doi:10.1016/j.apenergy.2018.04.074.
[89] Kim J, Noh Y, Chang D. Storage system for distributed-energy generation using liquid air combined with liquefied natural gas. Appl Energy 2018;212:1417–32. doi:10.1016/j.apenergy.2017.12.092.
[90] Krawczyk P, Szabłowski Ł, Karellas S, Kakaras E, Badyda K.*Comparative thermodynamic analysis of compressed air and liquid air energy storage systems*2018. doi:10.1016/j.energy.2017.07.078.
[91] Li Y, Cao H, Wang S, Jin Y, Li D, Wang X, et al. Load shifting of nuclear power plants using cryogenic energy storage technology. Appl Energy 2014;113:1710–16. doi:10.1016/j.apenergy.2013.08.077.
[92] Lee I, You F. Systems design and analysis of liquid air energy storage from liquefied natural gas cold energy. Appl Energy 2019;242:168–80. doi:10.1016/j.apenergy.2019.03.087.
[93] Wang C, Akkurt N, Zhang X, Luo Y, She X.*Techno-economic analyses of multi-functional liquid air energy storage for power generation, oxygen production and heating*2020. doi:10.1016/j.apenergy.2020.115392.
[94] Qi M, Park J, Kim J, Lee I, Moon I. Advanced integration of LNG regasification power plant with liquid air energy storage: Enhancements in flexibility, safety, and power generation. Appl Energy 2020;269:115049. doi:10.1016/j.apenergy.2020.115049.
[95] Briola S, Gabbrielli R, Delgado A.*Energy and economic performance assessment of the novel integration of an advanced configuration of liquid air energy storage plant with an existing large-scale natural gas combined cycle*2020. doi:10.1016/j.enconman.2019.112434.
[96] Li Y, Wang X, Jin Y, Ding Y. An integrated solar-cryogen hybrid power system. Renew Energy 2012;37:76–81. doi:10.1016/j.renene.2011.05.038.
[97] Li Y, Wang X, Ding Y. A cryogen-based peak-shaving technology: systematic approach and techno-economic analysis. Int J Energy Res 2013;37:547–57. doi:10.1002/er.1942.
[98] Kantharaj B, Garvey S, Pimm A. Compressed air energy storage with liquid air capacity extension. Appl Energy 2015;157:152–64. doi:10.1016/j.apenergy.2015.07.076.
[99] Luyao L, Sixian W, Zhang D, Luwei Y, Zhou Y, Wang J. Performance analysis of liquid air energy storage utilizing LNG cold energy. IOP Conf Ser Mater Sci Eng 2017;171. doi:10.1088/1757-899X/171/1/012032.
[100] Borri E, Tafone A, Comodi G, Romagnoli A. Improving liquefaction process of microgrid scale Liquid Air Energy Storage (LAES) through waste heat recovery (WHR) and absorption chiller. Energy Procedia 2017;143:699–704. doi:10.1016/j.egypro.2017.12.749.
[101] Ji W, Zhou Y, Sun Y, Zhang W, Pan CZ, Wang JJ.*Thermodynamic characteristics of a novel wind-solar-liquid air energy storage system*n.d. doi:10.1088/1757-899X/278/1/012070.
[102] Zhang T, Chen L, Zhang X, Mei S, Xue X, Zhou Y. Thermodynamic analysis of a novel hybrid liquid air energy storage system based on the utilization of. LNG cold energy. Energy 2018;155:641–50. doi:10.1016/j.energy.2018.05.041.
[103] Cetin TH, Kanoglu M, Yanikomer N. Cryogenic energy storage powered by geothermal energy. Geothermics 2019;77:34–40. doi:10.1016/j.geothermics.2018.08.005.
[104] Zhang T, Zhang XL, He YL, Xue XD, Mei SW. Thermodynamic analysis of hybrid liquid air energy storage systems based on cascaded storage and effective utilization of compression heat. Appl Therm Eng 2020;164. doi:10.1016/j.applthermaleng.2019.114526.
[105] Park J, You F, Cho H, Lee I, Moon I.*Novel massive thermal energy storage system for liquefied natural gas cold energy recovery*2020. doi:10.1016/j.energy.2020.117022.
[106] Gao Z, Guo L, Ji W, Xu H, An B, Wang J. *Thermodynamic and economic analysis of a trigeneration system based on liquid air energy storage under different operating modes*2020. doi:10.1016/j.enconman.2020.113184.
[107] Cetin TH, Kanoglu M, Bedir F.*Integration of cryogenic energy storage and cryogenic organic cycle to geothermal power plants*2020. doi:10.1016/j.geothermics.2020.101830.
[108] He T, Lv H, Shao Z, Zhang J, Xing X, Ma H. Cascade utilization of LNG cold energy by integrating cryogenic energy storage, organic Rankine cycle and direct cooling. Appl Energy 2020;277:115570. doi:10.1016/j.apenergy.2020.115570.
[109] Nabat MH, Zeynalian M, Razmi AR, Arabkoohsar A, Soltani M. Energy, exergy, and economic analyses of an innovative energy storage system; liquid air energy storage (LAES) combined with high-temperature thermal energy storage (HTES). Energy Convers Manag 2020;226:113486. doi:10.1016/j.enconman.2020.113486.
[110] She X, Zhang T, Peng X, Wang L, Tong L, Luo Y.*Liquid Air Energy Storage for Decentralized Micro Energy Networks with Combined Cooling, Heating, Hot Water and Power Supply*2021;30:1–17.
[111] She X, Peng X, Zhang T, Cong L, Ding Y. Preliminary study of Liquid Air Energy Storage integrated with LNG cold recovery. Energy Procedia 2019;158:4903–8. doi:10.1016/j.egypro.2019.01.702.
[112] Peng X, She X, Li Y, Ding Y. Thermodynamic analysis of Liquid Air Energy Storage integrated with a serial system of Organic Rankine and Absorption Refrigeration Cycles of driven compression heat Assessing the feasibility using by the heat demand-outdoor te. Energy Procedia 2017;142:3440–6. doi:10.1016/j.egypro.2017.12.227.
[113] Yu Q, Zhang T, Peng X, Cong L, Tong L, Wang L, et al. *Cryogenic Energy Storage and Its Integration With Nuclear Power Generation for Load Shift*2019. doi:10.1016/B978-0-12-813975-2.00008-9.
[114] Xu M, Zhao P, Huo Y, Han J, Wang J, Dai Y.*Thermodynamic analysis of a novel liquid carbon dioxide energy storage system and comparison to a liquid air energy storage system*2019. doi:10.1016/j.jclepro.2019.118437.
[115] Kantharaj B, Garvey S, Pimm A. Thermodynamic analysis of a hybrid energy storage system based on compressed air and liquid air. Sustain Energy Technol Assessments 2015;11:159–64. doi:10.1016/j.seta.2014.11.002.
[116] Barsali S, Ciambellotti A, Giglioli R, Paganucci F, Pasini G. Hybrid power plant for

energy storage and peak shaving by liquefied oxygen and natural gas. Appl Energy 2018;228:33–41. doi:10.1016/j.apenergy.2018.06.042.

[117] Hanak DP, Powell D, Manovic V. Techno-economic analysis of oxy-combustion coal-fired power plant with cryogenic oxygen storage. Appl Energy 2017;191:193–203. doi:10.1016/j.apenergy.2017.01.049.

[118] Pacheco KA, Li Y, Wang M. Study of Integration of Cryogenic Air Energy Storage and Coal Oxy-fuel Combustion through Modelling and Simulation. vol. 33. 2014. doi:10.1016/B978-0-444-63455-9.50091-X.

[119] Lockley A, von Hippel T. The carbon dioxide removal potential of Liquid Air Energy Storage: A high-level technical and economic appraisal. Front Eng Manag 2020. doi:10.1007/s42524-020-0102-8.

[120] Rehman A, Qyyum MA, Qadeer K, Zakir F, Ding Y, Lee M, et al. *Integrated biomethane liquefaction using exergy from the discharging end of a liquid air energy storage system*2020. doi:10.1016/j.apenergy.2019.114260.

[121] Ahmad A, Al-Dadah R, Mahmoud S. Liquid air utilization in air conditioning and power generating in a commercial building. J Clean Prod 2017;149:773–83. doi:10.1016/J.JCLEPRO.2017.02.143.

[122] Antonelli M, Desideri U, Giglioli R, Paganucci F, Pasini G. Liquid air energy storage: a potential low emissions and efficient storage system. Energy Procedia 2016;88:693–7. doi:10.1016/j.egypro.2016.06.100.

[123] Tafone A, Ding Y, Li Y, Xie C, Romagnoli A.*Levelised Cost of Storage (LCOS) analysis of liquid air energy storage system integrated with Organic Rankine Cycle*2020. doi:10.1016/j.energy.2020.117275.

[124] Park J, Lee I, You F, Moon I, Frederick R.*Economic Process Selection of Liquefied Natural Gas Regasification: Power Generation and Energy Storage Applications*2019. doi:10.1021/acs.iecr.9b00179.

[125] Pimm AJ, Garvey SD, Kantharaj B. Economic analysis of a hybrid energy storage system based on liquid air and compressed air. J Energy Storage 2015;4:24–35. doi:10.1016/j.est.2015.09.002.

[126] Jülch V. Comparison of electricity storage options using levelized cost of storage (LCOS) method. Appl Energy 2016;183:1594–606. doi:10.1016/j.apenergy.2016.08.165.

[127] Smallbone A, Jülch V, Wardle R, Roskilly AP. Levelised Cost of Storage for Pumped Heat Energy Storage in comparison with other energy storage technologies. Energy Convers Manag 2017;152:221–8. doi:10.1016/j.enconman.2017.09.047.

[128] Xie C, Li Y, Ding Y, Radcliffe J. Evaluating levelized cost of storage (LCOS) based on price arbitrage operations: With liquid air energy storage (LAES) as an example. Energy Procedia 2019;158:4852–60. doi:10.1016/j.egypro.2019.01.708.

[129] Kalavani F, Mohammadi-Ivatloo B, Zare K. Optimal stochastic scheduling of cryogenic energy storage with wind power in the presence of a demand response program. Renew Energy 2019;130:268–80. doi:10.1016/j.renene.2018.06.070.

[130] Vecchi A, Naughton J, Li Y, Mancarella P, Sciacovelli A. Multi-mode operation of a Liquid Air Energy Storage (LAES) plant providing energy arbitrage and reserve services e Analysis of optimal scheduling and sizing through MILP modelling with integrated thermodynamic performance 2020. doi: 10.1016/j.energy.2020.117500.

[131] Lin B, Wu W, Bai M, Xie C, Radcliffe J. Liquid air energy storage: Price arbitrage operations and sizing optimization in the GB real-time electricity market. Energy Econ 2019;78:647–55. doi:10.1016/j.eneco.2018.11.035.

[132] Zhang Q, Heuberger CF, Grossmann IE, Sundaramoorthy A, Pinto JM.*Optimal Scheduling of Air Separation with Cryogenic Energy Storage*. 2015. doi:10.1016/B978-0-444-63576-1.50072-8.

[133] Khani H, Zadeh MRD, Seethapathy R. Optimal weekly usage of Cryogenic Energy Storage in an open retail electricity market. IEEE Power Energy Soc Gen Meet 2013. doi:10.1109/PESMG.2013.6672626.

[134] Crotogino F, Mohmeyer K-U, Scharf R. Huntorf CAES : More than 20 Years of Successful Operation. In: Solut Min Res Inst Conf; 2001. p. 1–7.

[135] Georgiou S, Aunedi M, Strbac G, Markides CN. On the value of liquid-air and pumped-thermal electricity storage systems in low-carbon electricity systems. Energy 2020;193. doi:10.1016/j.energy.2019.116680.

[136] Wang P, Wang W, Wang C, Varga L. Optimal scheduling of multi-carrier energy networks considering liquid air energy storage. In: 2018 2nd IEEE Conf Energy Internet Energy Syst Integr; 2018. p. 1–4.

[137] Xu G, Deng Z, Cui S, Shi X, Lu C, Liang L, et al. Off-design Characteristics for Expansion Power Generation Process of Liquid Air Energy Storage System. IOP Conf Ser Earth Environ Sci 2020;603. doi:10.1088/1755-1315/603/1/012034.

[138] Vecchi A, Li Y, Mancarella P, Sciacovelli A. Integrated techno-economic assessment of Liquid Air Energy Storage (LAES) under off-design conditions: Links between provision of market services and thermodynamic performance. Appl Energy 2020;262:114589. doi:10.1016/j.apenergy.2020.114589.

[139] Shafiee S, Zareipour H, Knight AM. Considering Thermodynamic Characteristics of a CAES Facility in Self-Scheduling in Energy and Reserve Markets. IEEE Trans Smart Grid 2018;9:3476–85. doi:10.1109/TSG.2016.2633280.

[140] Bai J, Wei W, Chen L, Mei S.*Modeling and dispatch of advanced adiabatic compressed air energy storage under wide operating range in distribution systems with renewable generation*2020. doi:10.1016/j.energy.2020.118051.

[141] Khani H, Dadash Zadeh MR. Real-time optimal dispatch and economic viability of cryogenic energy storage exploiting arbitrage opportunities in an electricity market. IEEE Trans Smart Grid 2015;6:391–401. doi:10.1109/TSG.2014.2357253.

[142] Zhang Qi, Grossmann Ignatio E, Heuberger Clara F, Sundaramoorthy Arul, Pinto JM. Air Separation with Cryogenic Energy Storage: Optimal Scheduling Considering Electric Energy and Reserve Market. Alche 2015;61:1547–58. doi:10.1002/aic.14730.

[143] Ahmad A, Al-Dadah R, Mahmoud S. *Liquid nitrogen energy storage for air conditioning and power generation in domestic applications*2016. doi:10.1016/j.enconman.2016.09.063.

[144] Tafone A, Romagnoli A, Li Y, Borri E, Comodi G. Techno-economic Analysis of a Liquid Air Energy Storage (LAES) for Cooling Application in Hot Climates. Energy Procedia 2017;105:4450–7. doi:10.1016/j.egypro.2017.03.944.

[145] Comodi G, Carducci F, Sze JY, Balamurugan N, Romagnoli A. Storing energy for cooling demand management in tropical climates: A techno-economic comparison between different energy storage technologies. Energy 2017;121:676–94. doi:10.1016/J.ENERGY.2017.01.038.

[146] Zamani-Gargari M, Kalavani F, Abapour M, Mohammadi-Ivatloo B. Reliability assessment of generating systems containing wind power and air separation unit with cryogenic energy storage. J Energy Storage 2018;16:116–24. doi:10.1016/j.est.2017.12.013.

[147] Mazzoni S, Ooi S, Tafone A, Borri E, Comodi G, Romagnoli A. Liquid Air Energy Storage as a polygeneration system to solve the unit commitment and economic dispatch problems in micro-grids applications. Energy Procedia 2019;158:5026–33. doi:10.1016/j.egypro.2019.01.660.

[148] Kalavani F, Mohammadi-Ivatloo B, Karimi A, Kalavani F. Stochastic optimal sizing of integrated cryogenic energy storage and air liquefaction unit in microgrid. Renew Energy 2019;136:15–22. doi:10.1016/J.RENENE.2018.12.101.

[149] Fares RL, Webber ME. What are the tradeoffs between battery energy storage cycle life and calendar life in the energy arbitrage application? J Energy Storage 2018;16:37–45. doi:10.1016/j.est.2018.01.002.

[150] Frate GF, Ferrari L, Desideri U.*Critical review and economic feasibility analysis of electric energy storage technologies suited for grid scale applications*n.d. doi:10.1051/e3sconf/201913701037.

[151] Hou Q, Zhang N, Du E, Miao M, Peng F, Kang C. Probabilistic duck curve in high PV penetration power system: Concept, modeling, and empirical analysis in China. Appl Energy 2019;242:205–15. doi:10.1016/j.apenergy.2019.03.067.

[152] Moreno R, Moreira R, Strbac G. A MILP model for optimising multi-service portfolios of distributed energy storage. Appl Energy 2015;137:554–66. doi:10.1016/j.apenergy.2014.08.080.

[153] Park J, Lee I, Moon I.*A Novel Design of Liquefied Natural Gas (LNG) Regasification Power Plant Integrated with Cryogenic Energy Storage System*2017. doi:10.1021/acs.iecr.6b04157.

[154] Bai J, Chen L, Liu F, Mei S. Interdependence of electricity and heat distribution systems coupled by an AA-CAES-based energy hub. IET Renew Power Gener 2020;14:399–407. doi:10.1049/iet-rpg.2019.0660.

[155] Yan Y, Zhang C, Li K, Wang Z. An integrated design for hybrid combined cooling, heating and power system with compressed air energy storage. Appl Energy 2018;210:1151–66. doi:10.1016/j.apenergy.2017.07.005.

[156] Li Y, Wang X, Li D, Ding Y. A trigeneration system based on compressed air and thermal energy storage. Appl Energy 2012;99:316–23. doi:10.1016/j.apenergy.2012.04.048.

[157] Zhang H, Wang L, Lin X, Chen H.*Combined cooling, heating, and power generation performance of pumped thermal electricity storage system based on Brayton cycle2020*. doi:10.1016/j.apenergy.2020.115607.

[158] Steinmann WD, Bauer D, Jockenhöfer H, Johnson M, Steinmann WD, Bauer D, et al. Pumped thermal energy storage (PTES) as smart sector-coupling technology for heat and electricity. Energy 2019;183:185–90. doi:10.1016/j.energy.2019.06.058.

[159] Murrant D, Radcliffe J. Analysis of when and where the integration of LAES with refrigerated warehouses could provide the greatest value to. Europe. Energy Procedia 2018;151:144–9. doi:10.1016/j.egypro.2018.09.039.

[160] Frate GF, Ferrari L, Desideri U. Energy storage for grid-scale applications : Technology review and economic feasibility analysis. Renew Energy 2021;163:1754–72. doi:10.1016/j.renene.2020.10.070.

[161] Ahmad A, Al-Dadah R, Mahmoud S. *Air conditioning and power generation for residential applications using liquid nitrogen*2016. doi:10.1016/j.apenergy.2016.11.022.