Applied Energy 226 (2018) 1119–1133

Contents lists available at ScienceDirect

Applied Energy

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

A thermo-economic analysis and comparison of pumped-thermal and liquid-air electricity storage systems

Solomos Georgiou[a,b], Nilay Shah[b], Christos N. Markides[a,b,*]

[a] *Clean Energy Processes (CEP) Laboratory, Department of Chemical Engineering, Imperial College London, United Kingdom*
[b] *Centre for Process Systems Engineering (CPSE), Department of Chemical Engineering, Imperial College London, United Kingdom*

HIGHLIGHTS

- PTES has a lower TRL but the potential to achieve higher roundtrip efficiencies.
- LAES efficiency is enhanced through the utilisation of waste heat/cold streams.
- LAES has lower power/energy capital costs and a lower levelised cost of storage.
- PTES appears economically more competitive at higher electricity buying prices.
- Components involving power input/output dominate the initial capital expenditure.

ARTICLE INFO

Keywords:
Electricity storage
Liquid-air energy storage
Pumped-thermal electricity storage
Thermo-economic analysis

ABSTRACT

Efficient and affordable electricity storage systems have a significant potential to support the growth and increasing penetration of intermittent renewable-energy generation into the grid from an energy system planning and management perspective, while differences in the demand and price of peak and off-peak electricity can make its storage of economic interest. Technical (e.g., roundtrip efficiency, energy and power capacity) as well as economic (e.g., capital, operating and maintenance costs) indicators are anticipated to have a significant combined impact on the competitiveness of any electricity storage technology or system under consideration and, ultimately, will crucially determine their uptake and implementation. In this paper, we present thermo-economic models of two recently proposed medium- to large-scale electricity storage systems, namely 'Pumped-Thermal Electricity Storage' (PTES) and 'Liquid-Air Energy Storage' (LAES), focusing on system efficiency and costs. The LAES thermodynamic model is validated against data from an operational pilot plant in the UK; no such equivalent PTES plant exists, although one is currently under construction. As common with most newly proposed technologies, the absence of cost data results to the economic analysis and comparison being a significant challenge. Therefore, a costing effort for the two electricity storage systems that includes multiple costing approaches based on the module costing technique is presented, with the overriding aim of conducting a preliminary economic feasibility assessment and comparison of the two systems. Based on the results, it appears that PTES has the potential to achieve higher roundtrip efficiencies, although this remains to be demonstrated. LAES performance is found to be significantly enhanced through the integration and utilisation of waste heat (and cold) streams. In terms of economics on the other hand, and at the system size intended for commercial application, LAES (12 MW, 50 MWh) is estimated in this work to have a lower capital cost and a lower levelised cost of storage than PTES (2 MW, 11.5 MWh), although it is noted that the prediction of the economic proposition of PTES technology is particularly uncertain if customised components are employed. However, when considering the required sell-to-buy price ratios, PTES appears (by a small margin) economically more competitive above an electricity buy price of ~0.15 $/kWh, primarily due to its higher roundtrip efficiency. When considering the two systems at the same capacity, the costs are similar with a slight edge to PTES. Finally, it is of interest that the most expensive components in both systems are the compression and expansion devices, which suggests that there is a need to develop affordable high-performance devices for such systems.

* Corresponding author at: Clean Energy Processes (CEP) Laboratory, Department of Chemical Engineering, Imperial College London, United Kingdom.
E-mail address: c.markides@imperial.ac.uk (C.N. Markides).

https://doi.org/10.1016/j.apenergy.2018.04.128
Received 19 November 2017; Received in revised form 29 March 2018; Accepted 28 April 2018
Available online 26 June 2018

Nomenclature

C	specific waste cold, J kg^{-1} or cost
c	specific heat capacity, J kg^{-1} K^{-1}
D	diameter, m
F	factor
f	pressure loss factor
h	specific enthalpy, J kg^{-1}
I	cost index
l	losses
M	mass, kg
$\dot{m}$	mass flow rate, kg s^{-1}
P	pressure, bar
Q	heat, J (or Wh)
r	pressure ratio
s	specific entropy, J kg^{-1} K^{-1}
T	temperature, K
t	time, s
U	overall heat transfer coefficient, W m^{-2} K^{-1}
V	volume, m^3
W	work, J (or Wh)
$\dot{W}$	power, W
Greek letters	
β	heat leakage factor
ε	void ratio
η	efficiency
θ	temperature ratio
ρ	density
ω	uncertainty
Subscripts	
amb	ambient
B	base
BM	bare module
c	compressor or cold
ch	charge
ct	cryogenic turbine
dis	discharge
e	expander
ev	evaporation
h	hot
l	liquid
LA	liquid air
M	material
P	purchase
p	pressure or pump
rt	roundtrip
T	tank/storage vessel
t	turbine
v	vessel
Abbreviations	
BP	Buy Price
CAES	Compressed Air Energy Storage
LAES	Liquid-Air Energy Storage
LCOS	Levelised Cost of Storage
NPV	Net Present Value
PHS	Pumped Hydroelectricity (or Hydro) Storage
PHES	Pumped-Heat Electricity Storage
PTES	Pumped-Thermal Electricity Storage
SP	Sell Price
STB	Sell-to-Buy
TRL	Technology Readiness Level

Other symbols are defined in the text where they are used.

1. Introduction

The growth and increasing penetration of intermittent renewable-energy generation as part of a transition to more sustainable energy future [1,2] is expected to support the growing interest in energy storage. Energy storage can play a key role in enabling the widespread deployment of a range of distributed technologies, e.g., solar, for the generation of electricity [3–5], heat or both [6–8], across scales and applications. This paper focuses on electricity storage [9]. An affordable and efficient electricity storage technology can support this increased penetration and promote greater independence from fossil fuels, while being beneficial toward reduced emissions by displacing low-efficiency, low load-factor backup electricity generation as well as by avoiding the use of legacy plants used to meet peak demand. In regards to economics, electricity storage can become of financial interest by the difference between off-peak and peak demands and the consequential difference in the price of electricity. Nonetheless, important technical as well as economic performance indicators are known to have a considerable impact on the competitiveness of relevant solutions. Bulk electricity storage technologies with some commercialisation maturity, such as compressed air and pumped hydro, have been extensively studied in literature and have been demonstrated in large-scale plants [10]. However, limitations associated with these technologies, such as geographical and/or geological location restrictions, have encouraged the development of alternative electricity storage technologies, which are not (or, less) inherently restricted by these constraints.

The paper focuses on comparing from both technical and economic perspectives two such recently-proposed medium- to large-scale thermo-mechanical electricity storage technologies, namely liquid-air (LAES) and pumped-thermal electricity storage (PTES), which are currently under development but at different technology readiness levels (TRLs) [11]. The LAES system, a technology developed by Highview Power Storage [12], liquefies air at about −196 °C by using electricity and stores this at near atmospheric pressure in insulated storage vessels, therefore effectively storing electricity in the form of cold liquid air. When electricity is needed, the liquid air is pressurised, heated by exposure to ambient or even higher-temperature heat supplied by waste-heat sources, and finally expanded through a turbine to generate power [12,13].

The operation of a LAES system can be divided into three main stages/processes: charging, storage and discharging. Charging involves the supply of liquid air that can be provided by an independent supplier or an onsite air liquefaction plant, storage involves the storage of liquid air in an insulated vessel, and discharging involves power generation in the power recovery unit [13]. In this paper, a LAES system configuration is considered (as represented in Fig. 1) that uses an on-site liquefaction unit to liquefy air and waste heat is provided by an over-the-fence supplier, which is assumed to be available to the plant. Although LAES as a technology is considered emerging, the essential components for its construction can be considered mature and readily available [13], thus offering an advantage for rapid development. A working LAES pilot plant with a 350-kW power capacity and 2.5-MWh energy storage capacity is currently under operation [14,15], for which roundtrip efficiencies of 7–12% have been recorded depending on a number of operational parameters [13,14], although it is important to note that there is a significant potential for achieving considerably higher efficiencies at larger scales as has been suggested in Refs. [13–16]. The operation and performance of this LAES pilot plant as well as the prospective of the LAES system have also been studied in Refs. [14,15].

PTES (also referred to as 'pumped-heat electricity storage', or PHES, in the literature) is another recently proposed energy storage technology that stores electricity in the form of sensible heat in insulated storage vessels containing of an appropriate storage medium, such as a packed bed of gravel or pebbles [17]. PTES (presented in Fig. 2) comprises primarily two hot/cold thermal reservoirs (HR, CR) at different

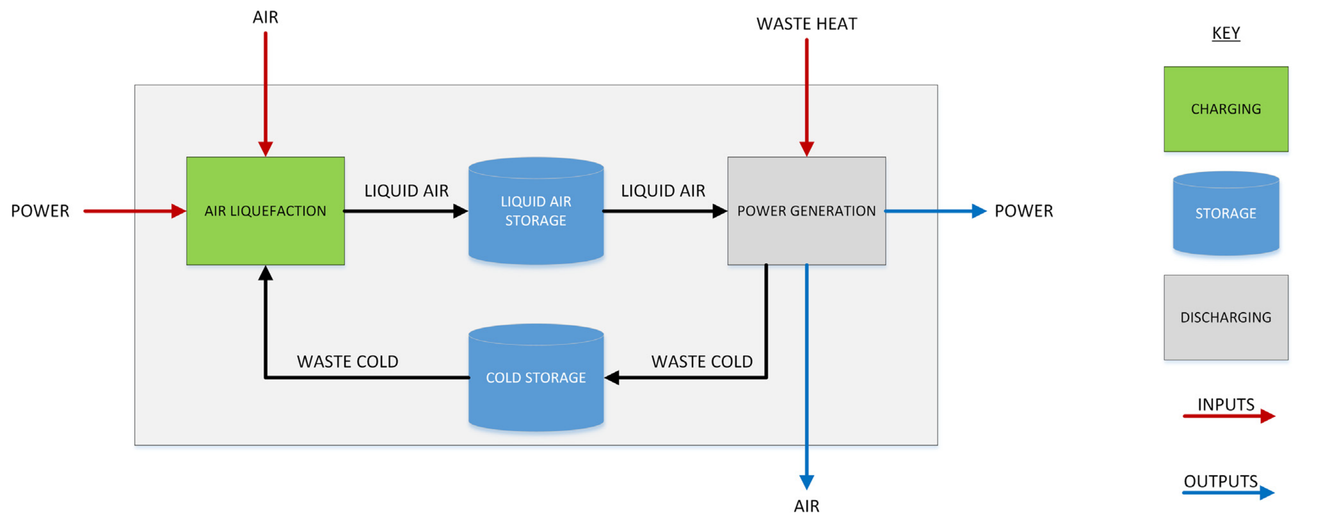

Fig. 1. LAES system representation and material/energy flows. Adapted from Ref. [14].

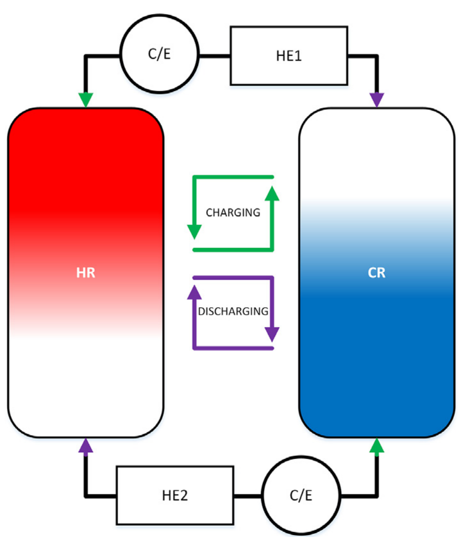

Fig. 2. PTES system configuration with main components. Adapted from Ref. [17].

pressures, two compression/expansion devices (C, E), and two heat exchangers (HE1, HE2) which are essential for accommodating the system's irreversibilities by heat rejection [17]. A PTES system runs reverse and forward Joule-Brayton cycles, for charging and discharging respectively. During the charge period, a high pressure-ratio heat-pump cycle is driven using electricity. This process removes heat from the cold vessel and supplies heat to the hot vessel. During the discharge period, the working fluid's flow direction is reversed within the system, and the difference in temperature between the two (hot/cold) thermal stores is used to drive a Joule-Brayton heat-engine cycle in order to generate work, and thereafter electrical energy [17,18].

In the conventional form of this energy storage technology, the working fluid proposed for the forward-reverse thermodynamic cycle is argon [17–19]. Earlier studies focussed on the modelling and loss mechanisms associated with the PTES configuration described above [17–20]. A similar PTES system but with some notable differences was introduced by Ref. [21], which employed a vapour compression heat pump for charging and an organic Rankine cycle (ORC) heat engine for discharging. Most interestingly, this system involves thermal integration of a low-grade heat source, which can increase the roundtrip efficiency of the system to values greater than unity. Another pumped-heat electricity storage configuration involving a compression heat pump and an ORC was considered in Ref. [22]. This study emphasised the specific requirements for ORC engine design in this application compared to common uses of this technology, with a particular focus on the working fluid requirements. The present paper focuses on the PTES system configuration described in Ref. [17] and shown in Fig. 2. PTES technology is at a lower TRL than LAES and, to the best of our knowledge, unlike the aforementioned LAES system, there is currently no operational PTES pilot plant, although one is currently being constructed in the UK for demonstration purposes.

The economic characteristics of such systems are vital for the employment of technologies, and these have been subject of earlier studies for different technologies [23]. Amongst the wide variety of technologies considered in Ref. [23], LAES is mentioned briefly, while a more generic reference to thermal storage technologies is made. Whereas the cost figures for LAES systems presented in Ref. [23] are very useful, since these cost projections are challenging to obtain for early-stage technologies, it is useful to apply multiple costing methods to observe the impact on the system's cost. In another interesting study [24], the authors explore the costs of a wide range of technologies, over a range of different capacities and under several applicability scenarios for each technology. Although LAES is mentioned as an emerging technology in this work, its costs are not considered. On the other hand, Ref. [25] focuses on the levelised cost of storage – an economic metric often used to assess the competitiveness of storage technologies – of: pumped hydroelectricity storage (PHS), compressed air energy storage (CAES), various battery technologies and power-to-gas storage. Likewise, Ref. [26] shows levelised costs of technologies including PHS, CAES and battery energy storage systems. Similarly, Refs. [27,28] considered the costs of storage technologies, including pumped-heat storage. It can be seen that a detailed costing exercise comparing LAES and PTES systems in these configurations, in particular based on a common methodology, is currently lacking.

LAES and PTES technologies are both capable of medium- to large-scale bulk electrical energy storage. Refs. [29,30] studied generic configurations of pumped-thermal and pumped-cryogenic electricity storage systems, which are the concepts followed by PTES and LAES, respectively. These insightful studies focused on the theoretical maximum performance of the two systems, based on Carnot heat pump or refrigeration, and Carnot heat engines. Ref. [29] concluded that the overall performance of the pumped thermal system was greater. Nonetheless, as far as the authors are aware, a direct comparison of the two systems based on the specific configurations introduced for their development in literature, the evaluation of their expected overall performance in an industrial operation while accounting for equipment performance, as well as an extension to include a comparison of their economic perspectives is lacking in the literature. Motivated by this gap in knowledge, in this paper we perform such a comparison while considering both the thermodynamic performance (focusing on roundtrip efficiency) and the economic feasibility of these systems, including factors such as (power, energy and absolute) capital costs, discount rates, electricity market variations (off-peak and peak demand operating points), levelised cost of storage (LCOS), net present values (NPVs), and sell-to-buy price ratios, all of which are significant factors that are expected to affect system competitiveness. In order to facilitate direct comparisons between the two systems with higher confidence, we develop a common modelling and thermo-economic assessment framework based on thermodynamic models, as well as common costing and financial feasibility models that we apply to both systems. In summary, this paper aims to give a high-level preliminary comparison between these technologies at their presented configurations, thus giving a first indication of their relative thermo-economic competitiveness.

2. Thermodynamic models

2.1. Liquid-air energy storage (LAES)

Following the thermodynamic principles and operation of the LAES system summarised in Section 1 and Fig. 1, a thermodynamic model has been developed with thermophysical properties taken from Ref. [31]. The roundtrip efficiency (η_{rt}) of this storage system is defined as the (net) work output (W_{dis}) during the discharge period divided by the (net) work input (W_{ch}) during the charge period:

$$\eta_{rt} = \frac{W_{dis}}{W_{ch}}. \tag{1}$$

For a full charge cycle, W_{ch} is evaluated by accounting for the specific work input required for liquid air production and the capacity of the liquid air storage tank (M_{LA}), or:

$$W_{ch} = w_l M_{LA}, \tag{2}$$

where w_l is the work input required per unit of mass of liquid air produced.

Considering a Claude cycle [32] (see Fig. 3) for the liquefaction process with the addition of thermal energy as 'cold recycle', which is the cold recovered during the evaporation of liquid air, the ideal w_l can be calculated from:

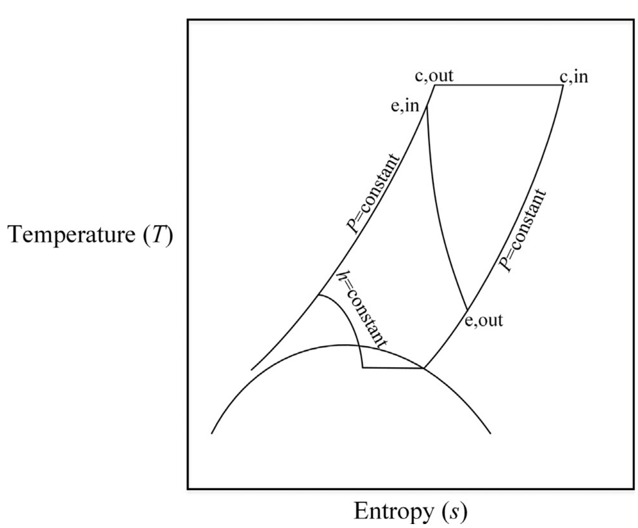

Fig. 3. *T-s* diagram of a LAES liquefaction (Claude) cycle. Adapted from Ref. [32].

$$w_l = \frac{[(T_{c,in}(s_{c,in}-s_{c,out})-(h_{c,in}-h_{c,out}))-x(h_{e,in}-h_{e,out})][(h_{c,in}-h_f)-C_r(1-L)]}{(h_{c,in}-h_{c,out})+x(h_{e,in}-h_{e,out})}, \tag{3}$$

where h_f is the specific enthalpy of air at atmospheric pressure and a quality of 0 (i.e. saturated liquid), and $T_{c,in}$ is the temperature of air at the inlet of the compressor. Furthermore, the terms h and s refer to the specific enthalpies and entropies at the inlet or outlet of the expander and compressor, distinguished by using subscripts 'in' and 'out' to represent inlet and outlet respectively, and subscripts 'e' and 'c' to represent expander and compressor respectively. Furthermore, x is the ratio of diverted mass of air for expansion to the total mass flow rate of compressed air. Lastly, C_r refers to the specific waste-cold available from the evaporation of liquid air during discharging, while $(1-L)$ is the ratio of recovered and recycled waste-cold delivered during charging.

To determine the recoverable C_r during the discharge period, we can evaluate the difference in the specific enthalpy between the fully evaporated air at ambient temperature and the specific enthalpy at the outlet of the cryogenic pump in the discharge cycle. Furthermore, it is also valuable to calculate the power capacity($\dot{W}_{ch}$) required for liquefaction during the charge phase, which is given by:

$$\dot{W}_{ch} = \dot{m}_{l,LA} w_l, \tag{4}$$

where $\dot{m}_{l,LA}$ is the liquid air mass production rate.

For the discharge cycle, W_{dis} is evaluated by integrating the net power output($\dot{W}_{dis,net}$) over the discharging time (t_{dis}) while assuming steady-state operation. The net power output($\dot{W}_{dis,net}$) is determined by finding the difference between the power input required for the cryogenic pump($\dot{W}_p$) to raise the liquid air to a specified pressure and the sum of power outputs($\dot{W}_t$) from the turbine stages (N_{ts}) while also taking into consideration the effect of reheating to a temperature of a waste-heat source where available. Thus, $\dot{W}_{dis,net}$ is given by:

$$\dot{W}_{dis,net} = \sum_{i=1}^{N_{ts}} \dot{W}_{t,(i)} - \dot{W}_p. \tag{5}$$

To conclude the discharge cycle, the maximum t_{dis} for the system from full storage capacity is simply calculated based on $\dot{m}_{l,LA}$ and M_{LA} while taking into account any evaporation losses (l_{ev}) that took place during idle time (t_{id}) as a result of heat gains from the environment (Q_{hg}). Assuming a fully charged state and overall heat transfer coefficient (U), a simplified estimation of l_{ev} is given by:

$$l_{ev} = \frac{\frac{Q_{hg} t_{id}}{h_f}}{M_{LA}}, \quad \text{where:} \quad Q_{hg} = U\left[\pi H_T D_T + \frac{\pi D_T^2}{2}\right](T_{amb} - T_T), \tag{6}$$

where H_T and D_T are the height and diameter of the storage tanks respectively, T_{amb} is the ambient temperature and T_T is the liquid air storage temperature. It is recognised that this estimation of l_{ev} is based on a plane-wall equation, whereas the storage vessels are in fact cylindrical. This is expected to introduce an error to the estimation but for this simplified evaluation the error is small and, therefore, can be neglected.

In order to calculate the required volume of the liquid air storage tank, we divide the storage capacity of the storage tank by the density of liquid air at storage conditions. The waste-cold storage volume (V_{wc}) requirement can be determined based on the ratio of the recovered waste-cold from the discharge cycle and the properties of the storage medium:

$$V_{wc} = \frac{M_{wc}}{\rho_{wc}(1-\varepsilon)}, \tag{7}$$

where ρ_{wc} is the density of the storage material assumed to be 5175 kg/m^3 [18], ε is the void ratio, and M_{wc} is the mass of the storage medium, in this case considered to be magnetite (Fe_3O_4).

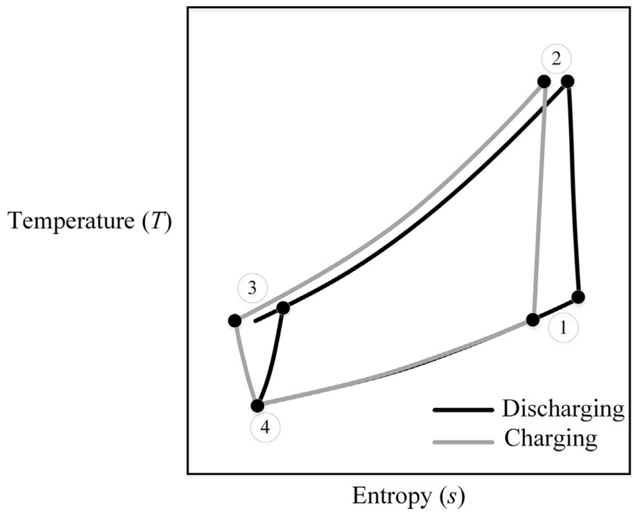

Fig. 4. *T-s* diagram for PTES charge and discharge cycles. Adapted from Ref. [18].

2.2. Pumped-thermal electricity storage (PTES)

The PTES system modelling approach followed in the present study is based on the model for this system proposed in Ref. [18], while incorporating certain aspects developed in Refs. [17,19,20]. A schematic for charge and discharge cycles of PTES is shown in Fig. 4. The concept of PTES is briefly described in Section 1 but for more details the interested reader can refer to Refs. [17,18].

Equivalently to the LAES system presented in Section 2.1, the roundtrip efficiency is of high interest and is defined as the (net) work output that can be extracted from the PTES system during the discharge cycle divided by the (net) work input required during the charge cycle, as in Eq. (1). As reported by Ref. [18], the most significant losses to account for in a PTES thermodynamic model are those due to flow/pressure and heat-transfer in: (i) the expansion and compression devices and (ii) in the thermal reservoirs. In this simplified model, the exit losses that are incurred due to thermal fronts reaching the outlet of the storage vessels are not considered, on the assumption that these components are designed to be just large enough to accommodate the required operation of the system.

For the compression and expansion devices, which are reciprocating machines, Ref. [18] proposes an effective way to model these devices while considering both irreversibility and heat leakage. This method differentiates between heat leakage and irreversibility by using of a heat leakage factor (β), defined as the ratio of instantaneous heat to work transfer, and a polytropic efficiency of expansion and compression (η) devices. Thus, the following equations are used for the compression and expansion processes:

$$\theta_c = r_c^{\phi_c}, \quad \theta_e = r_e^{\phi_e}$$
$$\text{where} \quad \phi_c = \frac{\gamma-1}{\gamma}\left(\frac{1-\beta_c}{\eta_c}\right) \quad \text{and} \quad \phi_e = \frac{\gamma-1}{\gamma}(1-\beta_e)\eta_e, \tag{8}$$

where θ_c, θ_e are the temperature and r_c, r_e the pressure ratios across the compressor and expander. Nominal values for η and β of 2% for both compression and expansion were estimated and used, as per Ref. [18].

Further, it is noted that any pressure losses in the hot and cold thermal reservoirs will also contribute towards a reduced pressure ratio across the expander compared to that across the compressor [18]. Hence, in order to accommodate for these pressure losses, a pressure loss factor (f_p) is introduced in the model and the polytropic relations above are adapted to:

$$\theta_e = (1-f_p)r_e^{\phi_e}. \tag{9}$$

Thereafter, the power input and output to/from the compressor and expander can be calculated by assuming quasi-steady processes. The power input to the compressor when charging, for instance, is given by:

$$\dot{W}_{c,ch,in} = \frac{\dot{m}c_p T_{c,ch,in}(\theta_c-1)}{1-\beta_c}, \tag{10}$$

where $T_{c,ch,in}$ is the temperature at the inlet of the compressor during the charging process, and $\dot{m}$ is the mass flow rate of the working fluid. Analogous expressions are employed for the expander as well as for discharging. Thenceforth, the power inputs and outputs can be integrated over the charge and discharge periods to calculate the work during one complete cycle.

Apart from the frictional pressure losses due to flow through the thermal reservoirs and their impact on the operation and performance of the compression and expansion devices, which is estimated through Eq. (9), a second source of loss in the system arises in the reservoirs that must be accounted for. This loss, which arises due to a thermal irreversibility, occurs due to heat transfer across the temperature difference between the gas and solid [17,18,33]. In Ref. [19] it was proven that reliable results, for the purposes of thermodynamic cycle analyses such as ours, can be obtained using an approximate loss analysis for the estimation of entropy generation rates as a result of these losses. The expressions developed in Ref. [19] for this loss estimation in simple packed-bed reservoirs due to pressure ('p') and thermal ('t') mechanisms are:

$$\frac{\dot{S}_p}{\dot{m}c_p} \approx \left[\frac{(\gamma-1)G^2R\overline{T}_gC_f}{2\gamma p^2\varepsilon^3 St}\right]\frac{\lambda_p}{l} \quad \text{and} \quad \frac{\dot{S}_t}{\dot{m}c_p} \approx \left(f_t\frac{\Delta T^2}{T_cT_d}\right)\frac{l}{\lambda_t}, \tag{11}$$

where G is the mass flux (i.e., flow rate per unit flow area),$\overline{T}_g$ refers to the average temperature of the gas, R is the gas constant (universal gas constant divided by the molecular mass), C_f refers to the friction coefficient, λ_p is the packed bed length, ε is the void ratio, St is the Stanton number and l refers to the thermal length scale. Also, f_t is a factor used to consider the shape of the thermal front, ΔT is the temperature difference between charge and discharge states, T_c and T_d are the temperatures at charge and discharge states respectively, and λ_t is the length of the thermal front. A more comprehensive discussion on this analysis can be found in Ref. [19].

The energy density of the system is of interest as a metric on its own right as well as for the costing of the necessary equipment. The nominal size of the reservoirs in terms of energy stored can be obtained by considering the difference in internal energies between the two reservoirs [18]. Using the nominal temperatures of the reservoirs, the stored energy (E) is calculated from [18]:

$$E = M_h c_{sh}(T_2-T_3-T_1+T_4), \tag{12}$$

where M_h is the mass of the and c_{sh} is the average specific heat capacity of the storage material in the hot reservoir, and T are the temperatures at the nominal operational points (states) presented in Fig. 4.

By setting the required energy storage, the mass required for the cold reservoir (M_c) can be estimated using Eq. (13) [18] and the required volume of both cold and hot reservoirs can be determined from Eq. (14):

$$M_c = M_h\left(\frac{c_{sh}}{c_{sc}}\right), \tag{13}$$

$$V = \frac{M}{\rho_s(1-\varepsilon)}, \tag{14}$$

where c_{sc} is the average specific heat capacity of the storage material in the cold reservoir over its operating temperature range, ρ_s is the density of the storage material and ε the void ratio in the hot or cold reservoirs.

3. Economic/cost estimates

3.1. Overall approach

The costing of emerging technologies is challenging and can involve substantial uncertainties. Consequently, tenders from manufacturers are usually essential for the improved accuracy of such costing exercises. In this paper, we are interested in a preliminary estimation of costs and a financial analysis of LAES and PTES systems that can act as an indicator for their relative financial feasibility and competitiveness. Since cost data for similar systems are not available to obtain estimates at a system level, the most important components of each system are costed individually and then summed to acquire an estimated system cost. The components of the two systems considered here include the pumps, heat exchangers, compressors, expanders/turbines, generators, and (pressurised or non-pressurised) storage vessels. Furthermore, we attempt to estimate and include installation costs where possible. It is currently not known which costing method available in the literature provides the most accurate estimates of the related equipment. Therefore, a variety of costing methods have been used in our analysis from which mean estimates have been obtained, along with associated uncertainty ranges based on minimum and maximum values. In this simplified approach, it is assumed that equipment can be used for the construction of the systems whose costs can be captured accurately by the standard correlations used in the costing methods implemented in this work. In the case of LAES this is assisted by the fact that many components are readily available (off-the-shelf), whereas in the case of PTES we assume that the cost of new equipment or components will be similar to those predicted by these existing correlations. This section provides a summary of each costing method used for the different elements of the systems of interest; further details can be found in the sources provided herein.

The equipment costing methods used in the present work are based on past literature data and cost surveys. Therefore, beyond the conversion of the cost estimates to the appropriate currency (the currency rates assumed for conversion from GBP (£) to USD ($) and from EUR (€) to USD ($) are: 1.39 $/£, 1.24 $/€), it is important to adjust these to current costs based on inflation and other economic conditions for the corresponding industry from the data collection time (i.e., base time) to the time of the analysis. This is performed through composite cost indexes, by using [34]:

$$C_{\mathrm{a}} = C_{\mathrm{b}}\left(\frac{I_{\mathrm{a}}}{I_{\mathrm{b}}}\right), \tag{15}$$

where C_{b} and C_{a} are the costs at data collection time and analysis time respectively, and I_{b} and I_{a} are the cost indexes at base and present year respectively. In the present study, the cost indexes used are based on the chemical engineering plant cost index (CEPCI), details of which can be found in Ref. [35].

3.2. Main components: Compressors, expanders/turbines, pumps and storage vessels

3.2.1. Turton et al. [34] method

The equipment module technique approach [34] provides estimate of the component costs of pumps, storage vessels, compressors, and expanders/turbines, and was selected because of its comprehensive consideration of aspects such as specific manufacturing materials, operating pressure where applicable, specific equipment type as well as direct and indirect costs related to the installation of the components. Based on Turton el al. [34], in this technique, firstly, the base cost of each component (C_{B}^0) is calculated in USD ($) from:

$$\log C_{\mathrm{B}}^0 = K_1 + K_2\log(A) + K_3[\log(A)]^2, \tag{16}$$

while assuming the manufacturing material to be carbon steel and operation at or near ambient pressure. In Eq. (16), A is the size or capacity of the component under consideration depending on which one of these two parameters has been used in the correlation plots to derive parameters K_1, K_2 and K_3 for that particular component (see, e.g., Ref. [34] for specific values and correlation charts). The values of K_1, K_2 and K_3 used in this analysis of the different components were taken from Ref. [34] and are presented in Table 1.

Table 1
Costing parameters obtained from Ref. [34] and used for estimations.

Parameter	K_1	K_2	K_3
Storage vessels	3.4974	0.4485	0.1074
Compressors	2.2897	1.3604	−0.1027
Pumps	3.3892	0.0536	0.1538
Turbines	2.7051	1.4398	−0.1776

Subsequently, the bare module cost (C_{BM}) is evaluated depending on the equipment type. This cost comprises direct and indirect costs for each element, as well as the impact of aspects that cause the element's cost to deviate from the base case conditions. In the case of compressors and power recovery systems we use [34]:

$$C_{\mathrm{BM}} = C_{\mathrm{P}}^0 F_{\mathrm{BM}}, \tag{17}$$

where F_{BM} is the bare module cost factor that is used as a multiplication factor to account for aspects associated with the installation and commissioning of the component and its manufacturing material. The bare module cost factors used in this analysis were obtained from Ref. [34] and took the values of 3.30 and 3.50 for compressors and power recovery systems respectively. For pumps and vessels, C_{BM} is calculated from [34]:

$$C_{\mathrm{BM}} = C_{\mathrm{P}}^0(B_1 + B_2F_{\mathrm{M}}F_{\mathrm{p}}), \tag{18}$$

where B_1 and B_2 are constants that can be found for each equipment based on its type (see, e.g., Ref. [34]), and F_{M} is the material factor which for this analysis is based on carbon steel construction for all equipment unless otherwise specified. For pumps the values used (all taken from Ref. [34]) were 1.89 and 1.35 for B_1 and B_2 respectively, while a material factor of 1.50 is also applied. For vessels, the constants B_1 and B_2 used for this analysis were 2.25 and 1.82 respectively. Finally, F_{p} refers to the pressure factor that is calculated for pumps and pressurised storage vessels from (respectively):

$$\log F_{\mathrm{p}} = C_1 + C_2\log(P) + C_3[\log(P)]^2, \tag{19}$$

$$F_{\mathrm{p,vessel}} = \frac{1}{0.0063}\left(\frac{(P+1)D}{2[850-0.6(P+1)]} + 0.00315\right)\text{for } t_{\mathrm{ves}} > 0.0063\text{ m}, \tag{20}$$

where C_1, C_2 and C_3 are constants obtained for different components from correlated data available in textbooks [34], P refers to the gauge pressure in bar, and D and t_{ves} are the diameter and thickness of the vessel. The values of the constants C_1, C_2 and C_3 used in this present analysis were −0.3935, 0.3957, −0.0023 respectively, as given in Ref. [34].

3.2.2. Seider et al. [36] method

Similarly to the Turton et al. [34] method presented above, the method proposed by Seider et al. [36] takes into account a variety of factors affecting the cost specific to each type of equipment. However, as shown below, the methodology and factors derived from cost correlations used by Ref. [36] differ. Hence, this method provides a second estimate of each component cost in USD ($).

To start with, the purchase cost of a compressor (C_{P}) is estimated by:

$$C_{\mathrm{P}} = F_{\mathrm{D}}F_{\mathrm{M}}C_{\mathrm{B,c}}, \tag{21}$$

where

$$C_{\mathrm{B,c}} = \exp\{R_{1,\mathrm{c}} + R_{2,\mathrm{c}}[\ln(Z)]\}. \tag{22}$$

Here, $C_{B,c}$ represents the compressor base purchase cost and it is calculated based on power consumption (Z) in horsepower, and factors $R_{1,c}$ and $R_{2,c}$ which vary depending on the selected compressor type. For this analysis, the values (all taken from Ref. [36]) $R_{1,c} = 7.9661$ and $R_{2,c} = 0.80$ were used, while the factors F_D and F_M that account for the electric motor drive and the construction material were assumed to be equal to 1.00.

Furthermore, the purchase cost of a vessel (C_P) is estimated by [36]:

$$C_P = F_M C_V + C_{PL}, \tag{23}$$

with:

$$C_V = \exp\{R_{1,v} + R_{2,v}[\ln(Y)] + R_{3,v}[\ln(Y)]^2\}, \quad \text{and,} \tag{24}$$

$$C_{PL} = R_{1,vp}(D)^{R_{2,vp}}(L)^{R_{3,vp}}, \tag{25}$$

where C_V is the vessel purchase cost calculated based on its weight (Y) in lb and factors $R_{1,v}$, $R_{2,v}$ and $R_{3,v}$ that vary according to its orientation, and C_{PL} is a function of the vessel's internal diameter (D), tangent-to-tangent length (L) and factors $R_{1,vp}$, $R_{2,vp}$ and $R_{3,vp}$ that account for the cost of platforms and ladders.

The purchase cost of pumps (C_P) is estimated from [36]:

$$C_P = F_J F_M C_{B,p}, \tag{26}$$

where the pump base purchase cost:

$$C_{B,p} = \exp\{R_{1,p} - R_{2,p}[\ln(S)] + R_{3,p}[\ln(S)]^2\} \tag{27}$$

is a function of the size factor $S = Q\sqrt{H}$, and factors $R_{1,p}$, $R_{2,p}$ and $R_{3,p}$, and Q is the volumetric flow rate in gallons per minute and H is the pump head in feet. The factors $R_{1,p}$, $R_{2,p}$ and $R_{3,p}$ (all taken from Ref. [36]) were assumed to take values of 9.7171, 0.6019 and 0.0519, respectively. Finally, the cost of the motor is added.

For power recovery turbines, the purchase cost (C_P) is a function of power recovery capacity in horsepower (Z), and factors $R_{1,t}$ and $R_{1,t}$ as shown in Eq. (28) [36]:

$$C_P = R_{1,t} Z^{R_{2,t}}. \tag{28}$$

For this analysis, $R_{1,t}$ and $R_{1,t}$ (all taken from Ref. [36]) were assumed to be equal to 530 and 0.81, respectively. Lastly, in order to take into account the indirect costs associated with each equipment, the bare module factors (F_{BM}) are applied to the purchase cost of each equipment/component as follows:

$$C_{BM} = C_P F_{BM}. \tag{29}$$

For all equipment, bare module factors were taken from Seider et al. [36] apart from power recovery turbines which were taken from Turton et al. [34]. Bare module factors used for this analysis are presented in Table 2.

3.2.3. Couper et al. [37] method

The Couper et al. [37] method is another equipment costing method found in literature, which follows a similar approach to Refs. [34,36] but again with different cost functions and correlation factors. As in Refs. [34,36], this method can be used to provide estimates of the cost of each component in USD ($).

Table 2
Bare module factors for Seider et al. [36] method (obtained from Refs. [34,36]) and for Couper et al. [37] method (obtained from Ref. [37]).

Parameter used	Seider et al. [36] method, F_{BM}	Couper et al. [37] method, F_{BM}
Storage vessels	4.16	2.80
Compressors	2.15	1.30
Pumps	3.30	2.80
Turbines	3.50	1.50

The purchase cost (C_P) of compressors and turbines is estimated from Eqs. (30) and (31) [37], which are functions of power capacity (Z) in horsepower as well as parameters which vary depending on the specific equipment type:

$$C_P = U_{1,c} Z^{U_{2,c}}, \tag{30}$$

$$C_P = U_{1,t} Z^{U_{2,t}}. \tag{31}$$

Values for $U_{1,c}$ and $U_{2,c}$ obtained from Couper et al. [37] for compressors were 7190 and 0.61, respectively. The respective values for turbines, $U_{1,t}$ and $U_{2,t}$, from Ref. [37], were 378 and 0.81. According to Ref. [37], the purchase cost (C_P) of vessels can be estimated from:

$$C_P = F_M C_V + C_{PL}, \tag{32}$$

where

$$C_V = U_{1,v}\exp\{U_{2,v} - U_{3,v}[\ln(Y)] + U_{4,v}[\ln(Y)]^2\}, \quad \text{and,} \tag{33}$$

$$C_{PL} = U_{1,vp}(D)^{U_{2,vp}}(L)^{U_{3,vp}}. \tag{34}$$

Parameters C_V, Y, C_{PL}, D and L were described in the previous section, whereas $U_{1-4,v}$ and $U_{1-3,vp}$ vary according to the vessel's orientation [37]. For this analysis $U_{1-4,v}$ were assumed to be 1.218, 9.100, 0.2889 and 0.04576, respectively (all taken from Ref. [37]). Similarly, parameters $U_{1-3,vp}$ were assumed to be 300, 0.7396 and 0.7066 (also taken from Ref. [37]).

The pump purchase cost (C_P) is determined from [37]:

$$C_P = F_J F_M C_B, \tag{35}$$

where

$$C_B = U_{1,p}\exp\{U_{2,p} - U_{3,p}[\ln(S)] + U_{4,p}[\ln(S)]^2\}, \quad \text{and,} \tag{36}$$

$$F_J = \exp\{U_{1,pt} + U_{2,pt}[\ln(S)] + U_{3,pt}[\ln(S)]^2\}. \tag{37}$$

Here, C_B is the base purchase cost which is a function of the size factor S as defined in the previous section, and parameters $U_{1-4,p}$, and F_J is the type factor that depends on S and parameters $U_{1-3,pt}$. Parameters $U_{1-4,p}$ used for this analysis were, as given in Ref. [37], 1.39, 8.833, 0.6019 and 0.0519 respectively. Parameters $U_{1-3,pt}$ were assumed to be 9.8846, −1.6164 and 0.0834 respectively (taken from Ref. [37]).

Finally, similar to the Seider et al. [36] method, the bare module factor for each equipment (shown in Table 2) is applied to account for its associated indirect costs as indicated by Eq. (29).

3.3. Other equipment

Since both systems use packed bed thermal stores (LAES for the waste-cold thermal store and PTES for the two reservoirs), estimates of the costs associated with the required storage material are applied with an assumed specific cost of magnetite of $139/t [19]. Also, since the waste-cold thermal store in the LAES system is not yet a commercially available technology [15], for the purpose of this costing exercise it is assumed to take the form of a simple packed bed similar to those used in the PTES system.

In the case of the generator cost, and since the applicable correlations for evaluating the base cost of the corresponding size or capacity similar to Refs. [34,36,37] do not exist to our knowledge, an alternative correlation based on the capacity exponent factor method is used with an exponent factor of 0.94 [38]:

$$C_B^0 = 1.85\cdot 10^6\left(\frac{\dot{W}}{1.18\cdot 10^4}\right)^{0.94}, \tag{38}$$

where C_B^0 is the base cost in EUR (€), and $\dot{W}$ is the power output in kW. Since operational conditions such as pressure are not relevant to this equipment, no correction factors were applied to this cost.

For costing the heat exchangers, a sizing exercise is first performed to find their area, which is determined using an overall heat transfer coefficient U from $A = \dot{Q}(U\cdot\Delta T_m)$, where $\dot{Q}$ is the duty of the heat exchanger, and ΔT_m is a suitable mean temperature difference. Unfortunately, in several cases of heat exchangers the definition of area can be complex. Consequently, in certain cases costing according to area might not be the most suitable approach for this kind of high level exercise. In such cases, the "C-value" method can be used to provide a more intuitive costing for comparison [39]. This approach avoids the complexity associated with area definition by providing the cost in terms of the heat exchanger duty ($\dot{Q}$) and the available driving force, which is the mean temperature difference (ΔT_m) [39]. Therefore, the "C-value" cost (CV) is given per unit of $\dot{Q}/\Delta T_m$ and it is acquired from tabulated data available for example in Ref. [39]. Hence, based on logarithmically interpolated CV values, the heat exchanger's (CE) capital cost is:

$$CE = CV\cdot\frac{\dot{Q}}{\Delta T_m}. \tag{39}$$

Compared to the cost estimates obtained from the methods that rely on knowledge of the heat transfer area, such as those proposed in Refs. [34,36,37], the "C-value" method has been found to generally overestimate the cost of the heat exchangers. Based on preliminary cost estimates using the "C-value" method, however, the cost of the heat exchangers was found to represent a small share of the overall LAES/PTES system costs, thus suggesting that this does not considerably affect the estimation of the overall system costs in this study.

4. Results

4.1. Thermodynamic performance analysis

LAES technology has been demonstrated to some extent, with the construction and testing of a pilot plant with a rated power of 350 kW and energy storage capacity of 2.5 MWh, and is therefore at a higher TRL than PTES technology. A comparison of data from this first LAES pilot plant, taken from Refs. [13,14], against our model predictions is used here to validate the model developed in the present study. Uncertainties in the model input parameters and variables (as described in Section 2) were quantified by considering upper and lower bounds for the outputs generated by the model. This overall uncertainty was obtained from [40]:

$$\omega_R = \left[\left(\frac{\partial R}{\partial x_1}\omega_1\right)^2 + \left(\frac{\partial R}{\partial x_2}\omega_2\right)^2 + \ldots + \left(\frac{\partial R}{\partial x_n}\omega_n\right)^2\right]^{1/2}, \tag{40}$$

where ω_R is the overall uncertainty in a particular output quantity, and $\omega_1,\omega_2,\ldots,\omega_n$ are the uncertainties associated with the n independent input variables used in the model to evaluate ω_R.

Since the pilot plant is a first-of-a-kind (FOAK) and was tested under varying conditions, its components are expected to experience sub-optimal operation (and performance). Therefore, based on nominal (intermediate 'best' guess) values presented in Table 3, Fig. 5 shows results obtained from the present LAES system model relating to: (i) the system roundtrip efficiency as a function of specific cold recycled (Fig. 5a), (ii) the liquefier specific work input for varying specific cold recycled (Fig. 5b), and (iii) the gross motor power as a function of the temperature at the turbine inlet (Fig. 5c). These plots show very good agreement with the pilot plant data, and therefore act as validation of the LAES system model, at least within this range of parameters, providing confidence in some of the results presented further down this paper outside this range.

The LAES pilot plant operates under conditions that contribute towards its observed low efficiency. This can be increased by changing operational parameters such as the pressure at the outlet of the pump ($P_{p,out}$), the cold utilised during air liquefaction ($C_r(1-L)$), and the temperature at the inlet of the turbine ($T_{t,in}$) during discharge, as well as improving equipment performance that can be achieved in more efficient plants at larger scales. The impact of these parameters on the roundtrip efficiency was examined and is shown in Fig. 6 when varying only the examined parameter and keeping all others at their nominal values given in Table 3.

Fig. 6a shows that, in terms of losses, the most influential factors on the roundtrip efficiency of LAES are the efficiencies of the cryogenic turbine in the liquefaction plant, the compressor, and the turbine in the power generation unit. The efficiency of all three components shows a similar, positive linear relationship with the system's roundtrip efficiency. In Fig. 6b we consider variations to important operational factors, including the amount of cold recycled and utilised which, for +ve deviations from the nominal values, is clearly found to be the dominant factor. However, when −ve deviations from the nominal value are considered, its effect is similar in magnitude to that of the turbine inlet temperature $T_{t,in}$. The pressure increase at the pump outlet is also found to be a contributing factor towards a higher roundtrip efficiency over the range considered of parameters although less so.

Considering now PTES, as with LAES, both loss and operational parameters are expected to impact this technology's roundtrip efficiency. The overall PTES system performance and effects of key loss parameters have been studied extensively and presented in Ref. [18]. In particular, model simulations have highlighted the significance of the pressure ratio between the two thermal stores on the performance of the system. Present predictions of the net power input during charge and the net power output during discharge using the nominal values presented in Table 4, are similar to the earlier work, and show a monotonic increase with increasing pressure ratio over the examined range with minimum, nominal and maximum values of 2.9, 11.5 and 20.0 (Fig. 7a). Even though the difference between the power input and output widens as the pressure ratio increases, the roundtrip efficiency still improves. Interestingly, it is observed from Fig. 7b that the effect on the roundtrip efficiency of increasing the pressure ratio at −ve deviations from nominal is significantly greater than at +ve deviations, such that the benefit in efficiency from increasing the pressure ratio decreases substantially at higher pressure ratios. This is evident at the −ve extreme end of pressure ratios where an increase in roundtrip efficiency of around 20% absolute, or close to 50% relative, is achieved by an increase in normalised pressure ratio of just 0.17 (from −0.50 to

Table 3
Nominal (intermediate 'best' guess) values for the LAES pilot plant (350 kW, 2.5 MWh) and nominal LAES plant (12 MW, 50 MWh) model values used in the parametric analysis.

Parameter	η_t Turbine isentropic efficiency	η_{ct} Cryogenic turbine isentropic efficiency	η_p Cryogenic pump isentropic efficiency	l_p Pressure loss factor	η_c Compressor efficiency	$P_{p,out}$ Pump outlet pressure (bar)	$T_{t,in}$ Turbine inlet temperature (K)	$C_r(1-L)$ Specific waste-cold utilisation (kJ/kg)
Nominal (intermediate 'best' guess) values for pilot plant	0.60	0.80	0.60	10%	0.80	56	337	–
Nominal values for parametric analysis	0.85	0.85	0.85	10%	0.85	170	393	170

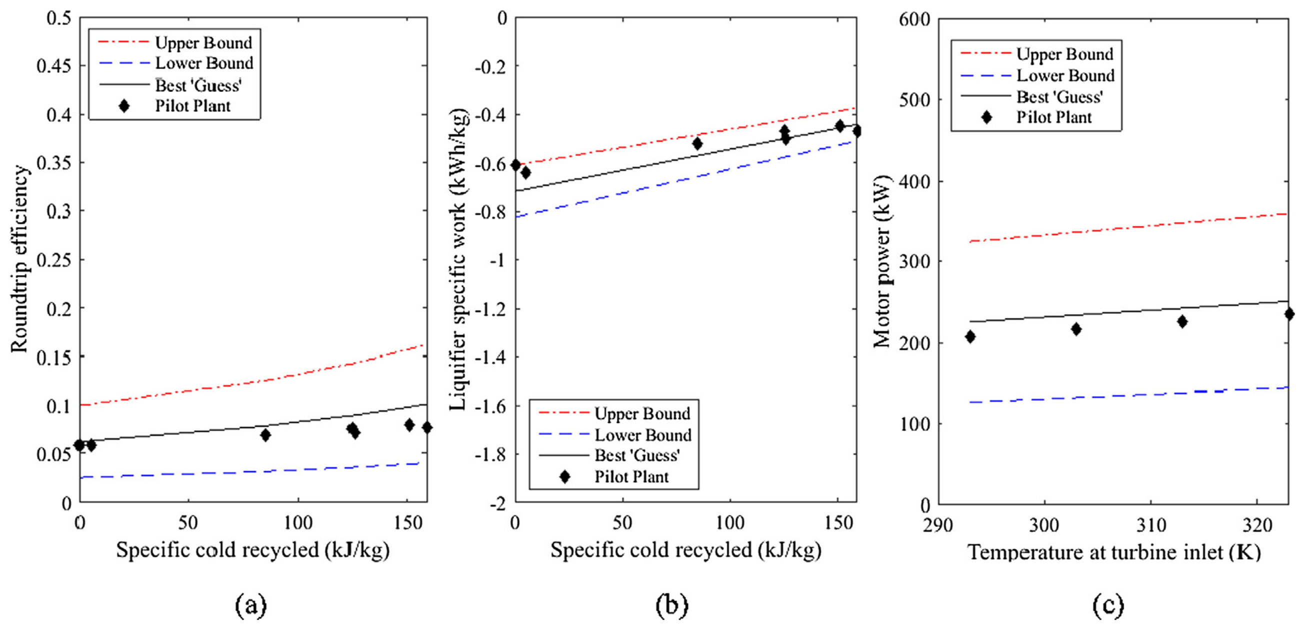

Fig. 5. Comparison of LAES model outputs with pilot-plant data: (a) roundtrip efficiency against specific cold recycled (per kg) of processed liquid air, (b) liquifier specific work against specific cold recycled, and (c) gross motor power against temperature at the turbine inlet; based on the model parameters and variables in Table 3.

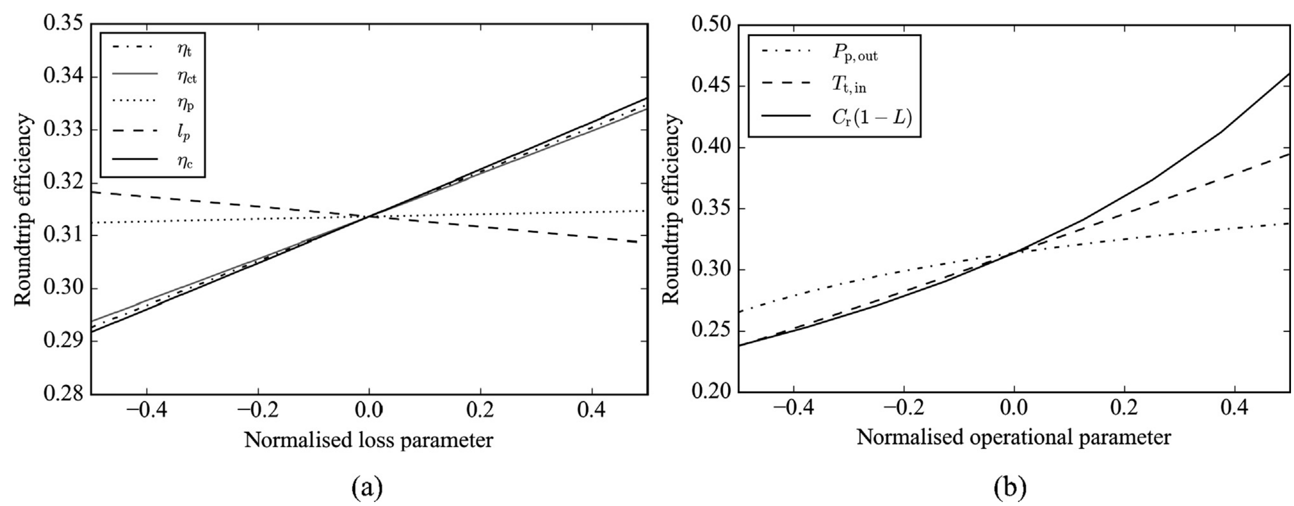

Fig. 6. LAES roundtrip efficiency against: (a) normalised loss parameters, $(y-\bar{y})/(y_{max}-y_{min})$ and (b) normalised operational parameters; based on the model parameters and variables in Table 3.

−0.33). Subsequently, when other factors such as material strengths and costs involved are accounted for, the increase in pressure ratio beyond a certain point may not be beneficial in a cost-benefit optimisation analysis.

The roundtrip efficiency at the higher end of pressure ratios reaches values of ~80%, which is considered high. These predictions should be seen in light of component performance estimates that have not yet been proven [18]. The roundtrip efficiency is also expected to decrease with the increase in storage time as a result of heat losses to the environment, especially if the storage vessels are not well insulated. Nevertheless, with sufficient insulation these heat losses can be reduced [18], especially in a system which is aimed for frequent use without long idle storage durations. Subsequently, they are not considered in the present analysis.

In conclusion to this section, in general PTES achieves a (theoretical) higher roundtrip efficiency of more than 75% at the highest operating pressure ratios considered in this work. Nonetheless, LAES shows significant improvement from its nominal design through the

Table 4
Nominal PTES plant (2 MW, 11.5 MWh) model values used in the analysis.

Parameter	T_c Cold reservoir discharged state temperature (K)	T_h Hot reservoir discharged state temperature (K)	β Heat leakage factor	l_p Pressure loss factor	η Compression/expansion devices polytropic efficiency	r Pressure ratio
Nominal values	310	310	0.02	0.02	0.98	11.5

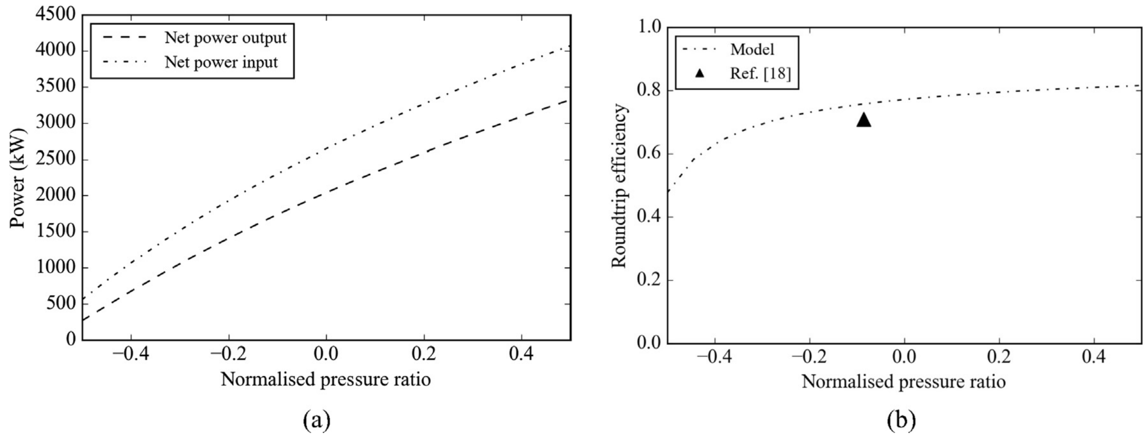

Fig. 7. PTES: (a) power input and output against normalised pressure ratio, $(y-\bar{y})/(y_{max}-y_{min})$ and (b) roundtrip efficiency against normalised pressure ratio from the model, also showing a comparison to a result from Ref. [18]; based on the model parameters and variables in Table 4.

sufficient utilisation of waste cold and heat, attaining a roundtrip efficiency of more than 55% when a combination of these two factors is adapted.

4.2. Thermo-economic analysis

In this section, the economics of a LAES system with a rated power of 12 MW and a rated energy-storage capacity of 50 MWh are studied. This system is larger than the pilot plant considered in Section 4.1, while maintaining a power to energy-storage ratio close to that proposed in Ref. [13] for commercial-scale systems. The chosen power rating and energy-storage capacity of the LAES system considered here are also close to the commercial-scale plant considered in Ref. [13], which was judged to be viable for implementation. Furthermore, the cost estimation was performed based on the nominal design values used in Section 2, apart from the quantity of utilised waste cold, which was considered to be at 250 kJ/kg as it was found to have a significant influence on the performance of the system, and it can be achievable in a commercial-scale plant [14]. Finally, it is assumed, due to the large uncertainty in this cost component, that over-the-fence waste heat at 393 K at no additional cost is utilised for the case of LAES. If an additional cost is imposed due to the waste heat utilisation, it can be added to the operational costs of the system. It is therefore expected to have an impact on the system's overall financial feasibility proportionate to the additional cost. This aspect, however, is expected to be case specific and it is not considered as an additional cost here.

For PTES, the power rating and energy-storage capacity of the system considered in the present economic analysis were 2 MW and 11.5 MWh, respectively, which are also close to the capacities studied and found to be viable in Refs. [18,19]. It is anticipated that higher capacities may be achievable at a more advanced level of technology development and readiness. As with the LAES system, the parameters considered for the economic analysis of the PTES system were the nominal values considered above.

First of all, the power capital cost (defined here, in alignment with the relevant literature, as the total capital cost per unit of rated power output) of both systems was estimated considering the overnight purchase and installation costs for each system. LAES was found to a have lower power capital cost than PTES, with the ranges for the two being 1.43–2.73 $K/kW and 2.99–6.09 $K/kW, respectively (Fig. 8a). In addition, the uncertainty in the PTES predictions is clearly greater (about double) showing the impact of capital cost variation from the different cost estimation methods, particularly for the compression and expansion devices. While compression and expansion devices are used in both

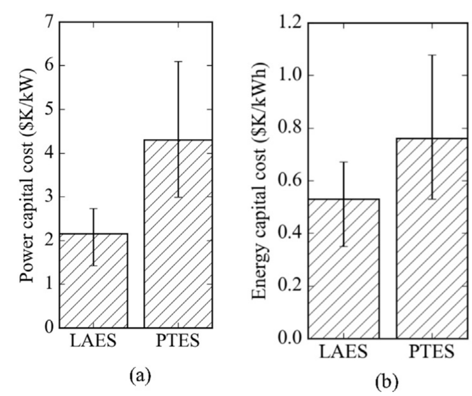

Fig. 8. (a) Power capital cost of LAES and PTES. (b) Energy capital cost of LAES and PTES. The error bars indicate the variations (min-max) obtained when using the different costing methods in Section 3.

technologies, LAES employs turbomachinery for expansion whereas PTES employs reciprocating machines as expansion/compression devices [18]. This is expected to affect the the costs of the two systems.

The energy capital cost (defined as the total capital cost per unit of rated energy output) was also estimated considering overnight purchase and installations costs. The relative difference in energy capital cost between the two systems was found to be considerably less than their difference in power capital cost. LAES was estimated to be in the range of 0.35–0.67 $K/kWh, and PTES in the range of 0.53–1.08 $K/kWh (Fig. 8b). The smaller difference is possibly attributed with the higher rated energy capacity to power ratio associated with PTES. This is, as expected, applicable to the intended capacities and setups analysed here and can differ when considering other variations. An additional comparison of the two systems while at equal capacities is presented in Section 4.3, although it is worth noting that those are not the intended capacities for application.

The allocations of capital expenditure (based on mean values) to the main components of both systems were also estimated. Components involving power generation and/or consumption were accountable for the greatest capital cost shares in both systems, while the thermal storage components were accountable for substantially smaller shares (see Fig. 9a and b). For instance, the compressor/expander machines in the PTES system were found to account for almost 80% of the total capital cost of this system. Similarly, the liquefaction plant and power recovery plant of LAES system were found to cumulatively account for

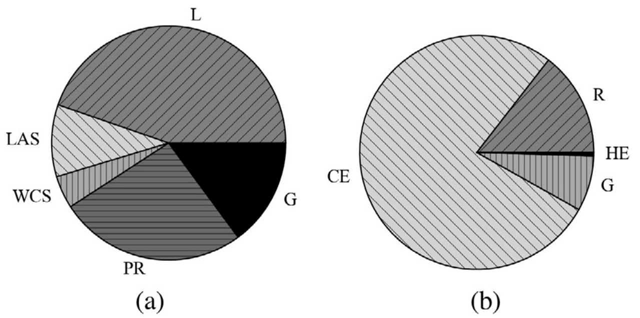

Fig. 9. Capital cost allocation to the main components of: (a) LAES (L: liquefaction plant, LAS: liquid air storage, WCS: waste cold storage, PR: power recovery, G: generators) and (b) PTES (R: reservoirs, CE: compressors/expanders, G: generators, HE: heat exchangers).

about 70% of its total capital cost. Subsequently, once more, the practice of waste-cold utilisation can play a crucial role in the LAES system, since the decrease in quantity of utilised waste-cold can allow an increase in the power and energy capital costs of LAES as a result of the requirement of a higher power capacity compressor capable to match the equivalent liquid air yield.

Furthermore, the allocation of capital expenditure for LAES with respect to rated power output, energy capacity and absolute cost is shown in Fig. 10a–c, respectively. The liquefaction plant was found to be responsible for the greatest share in all three metrics while also showing the greatest cost variation; the power recovery unit follows second. Similarly, for PTES the allocation of capital in terms of rated power output, energy capacity and absolute cost is shown in Fig. 11a–c, respectively. For PTES, the compression/expansion devises were clearly found to be the dominant costs while also presenting the greatest variation from the different costing methods.

An increase in energy or power output capacity is expected to increase the capital cost but potentially also increase the financial income from the operating the system, if it is utilised correctly, leading potentially to benefits from economies of scale. Since power consumption and/or generation devices were found to be more capital intensive, a marginal increase in rated power input or output should justify a higher marginal benefit in comparison to increasing energy capacity. Assuming scalability of the corresponding technology permits, the optimal energy to power ratio from an economic perspective should aim in the minimisation of both power and energy capital costs. This is expected to be case specific and depended on a variety of factors, such as the electricity market and the variations in electricity prices.

In order to consider these technologies within the wider context of

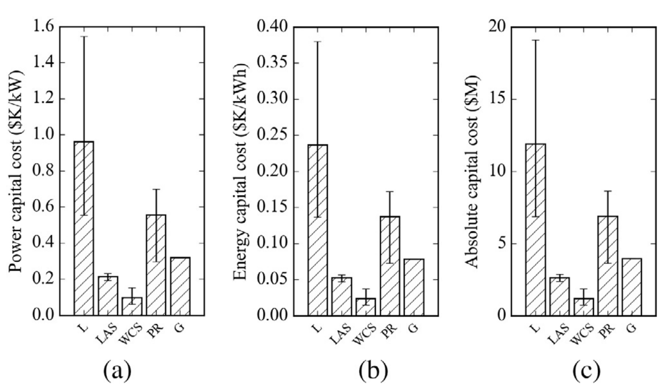

Fig. 10. (a) Power capital cost, (b) energy capital cost, and (c) absolute capital cost allocation to the main components of LAES (L: liquefaction plant, LAS: liquid air storage, WCS: waste cold storage, PR: power recovery, G: generators). The error bars indicate the variations (min-max) obtained when using the different costing methods in Section 3.

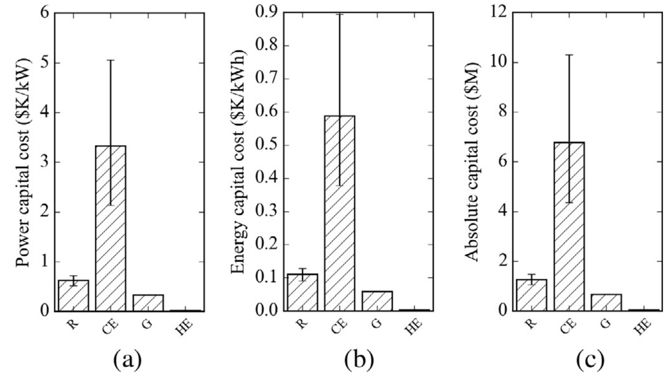

Fig. 11. (a) Power capital cost, (b) energy capital cost, and (c) absolute capital cost allocation to the main components of PTES (R: reservoirs, CE: compressors/expanders, G: generators, HE: heat exchangers). The error bars indicate the variations (min-max) obtained when using the different costing methods in Section 3.

competing electricity storage solutions, it is useful to refer to the chart compiled by the Energy Storage Association (ESA) based on literature data, shown in Fig. 12. In this chart, we have also overlaid the expected performance of LAES and PTES in their intended application. The figure shows that both technologies are aimed for energy management applications in the range of medium- to large-scale storage technologies. On the basis of this comparative chart, while also bearing in mind the respective capital costs of these two systems, it can be inferred that LAES can be more competitive than PTES in terms of power capital cost (Fig. 13). In addition, LAES is found to be competitive against technologies such as PHS, lithium-ion batteries, sodium sulfur batteries and hydrogen fuel cells. It is also notable that the power capital cost ranges of the aforementioned technologies are greater than the range estimated for LAES and similar to that for PTES.

We now turn our attention to the financial feasibility of the two electricity storage systems over their lifetime, which is assumed in this work to be 30 years of daily cycling (i.e., 365 cycles per year) without component degradation. For this financial feasibility analysis, we incorporate the upfront capital expenditure along with its associated discount rate, the operational energy costs, and the annual maintenance costs. Since novel technologies, which lack plants at the commercial scale, are considered in both cases, non-negligible uncertainties exist in the maintenance costs and in the assignment of discount rate values from a commercial private perspective. Therefore, a range of maintenance costs and discount rates were employed for the execution of the analysis. In the case of discount rates, the ranges considered were 6–12% for LAES and 9–15% for PTES to accommodate for the potential higher risk of investment associated with the lower maturity of the technology [43]. For annual maintenance costs, the variation was considered to be in the range of 1.5–3.0% of the initial capital expenditure [13] for both technologies. Similarly, an additional important level of uncertainty is introduced by the energy cost as it depends on various varying aspects such as location and fuel prices. Hence, the analysis was performed while considering a range of 0.028–0.083 $/kWh for off-peak electricity costs [44]. The uncertainties and consequently the sensitivity of the systems on these variables is captured by the error bars or bounds indicated in Figs. 14 to 16.

The financial analysis of the systems also included the total levelised cost of storage (LCOS) (Fig. 14a) as well as their main cost elements independently (Fig. 14b) on which each of the uncertainties considered is anticipated to have a different impact. With respect to the average total LCOS, the two systems were found to be close, with values of 0.29 $/kWh for LAES and 0.38 $/kWh for PTES. Considering the range of LCOS, LAES was found to be in the range of 0.14–0.46 $/kWh and PTES in the range of 0.20–0.65 $/kWh. It is also noteworthy that for PTES the operational energy costs account for less than half of the

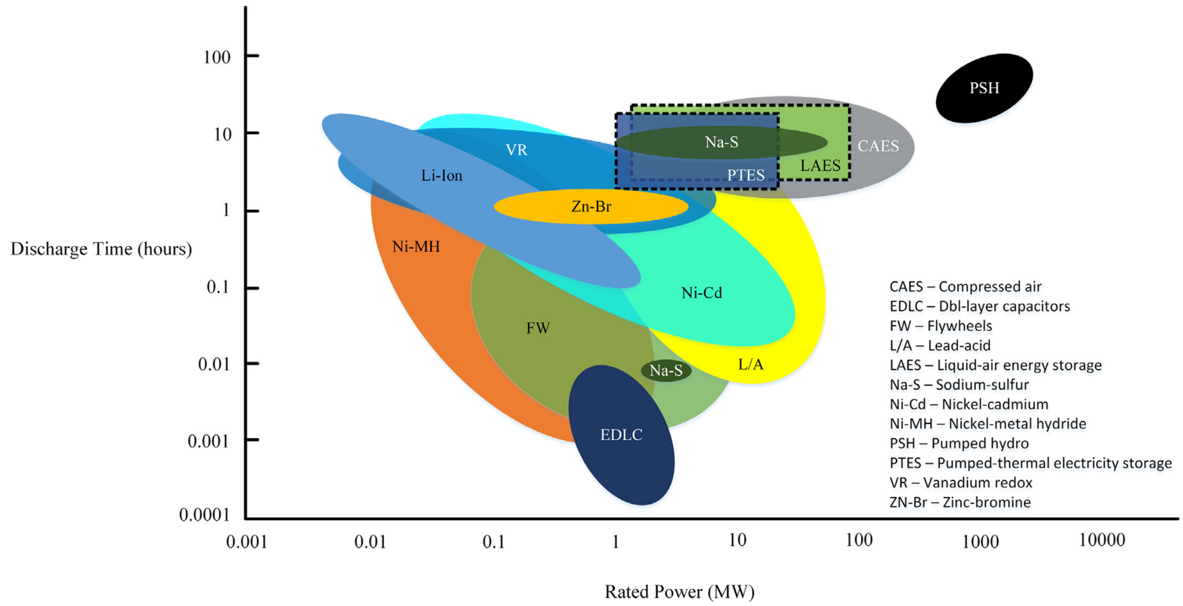

Fig. 12. Application comparison for various energy storage technologies with the addition of PTES and LAES technology as intended for commercial application; taken and adapted from Refs. [41,42].

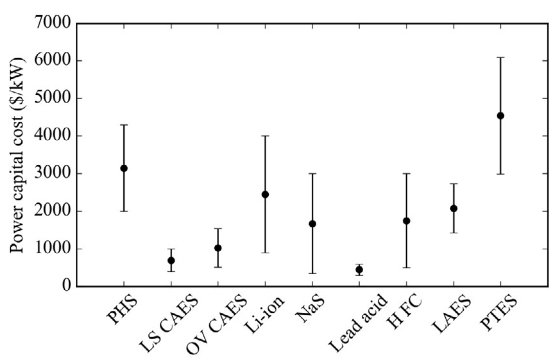

Fig. 13. Comparison between existing electricity storage technologies (PHS: pumped hydroelectricity storage, LS CAES: large scale underground compressed air electricity storage, OV CAES: over ground compressed air electricity storage, Li-ion: lithium ion batteries, NaS: sodium sulphur batteries, Lead acid: lead acid batteries, H. FC: hydrogen fuel cell) and LAES and PTES in terms of power capital cost (data for all technologies except LAES and PTES were obtained from Ref. [23]).

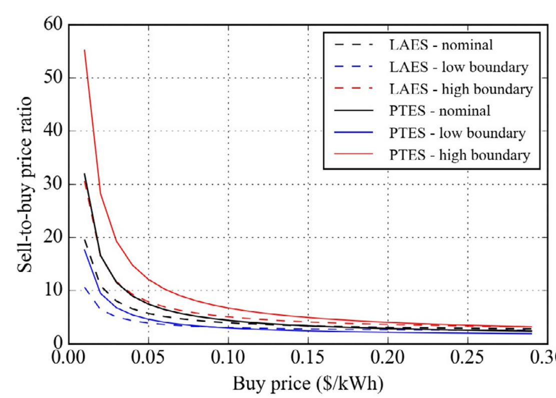

Fig. 15. Comparison between LAES and PTES in terms of required sell-to-buy price ratio against the electricity buying price. The high-low bounds indicate the variations (min-max) obtained when using the different costing methods in Section 3 and the variability associated with the uncertainty factors where applicable.

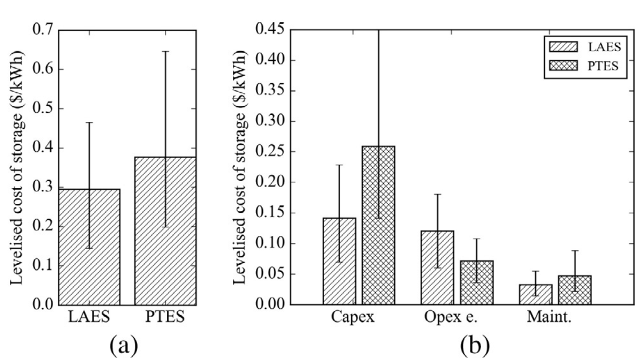

Fig. 14. (a) Overall levelised cost of storage (LCOS). (b) LCOS per expenditure category (Capex: capital expenditure, Opex e.: operational expenditure for energy, Maint.: maintenance costs). The error bars indicate the variations (min-max) obtained when using the different costing methods in Section 3 and the variability associated with the uncertainty factors where applicable.

capital expenditure whereas for LAES the allocation to capital expenditure and operational energy costs are similar. Moreover, less uncertainly was noted in LCOS corresponding to operational energy costs for PTES than LAES when both systems were examined over the same cost range. However, a much greater uncertainty was observed in the LCOS associated with capital expenditure of PTES in comparison to the uncertainty associated with its operational energy costs, as well as the equivalent capital cost uncertainty of LAES. This justifies the greater sensitivity noted on the total LCOS of PTES. Subsequently, since the only uncertainty considered which affects the estimated LCOS allocated to operational energy costs is the energy price, LAES is found to be more restrictive to location due to energy cost and more vulnerable to market fluctuations of electricity prices. This effect is potentially a consequence of the lower roundtrip efficiency observed in the LAES system and subsequently due to the greater energy input requirements per energy unit output. On the contrary, LAES's LCOS allocation to capital cost and its resulting sensitivity is considerably lower than PTES; thus presenting a lower risk related with capital investment. Additionally, it is worth noting that an improvement in roundtrip efficiency is expected to decrease the LCOS associated with operational energy costs but that is not

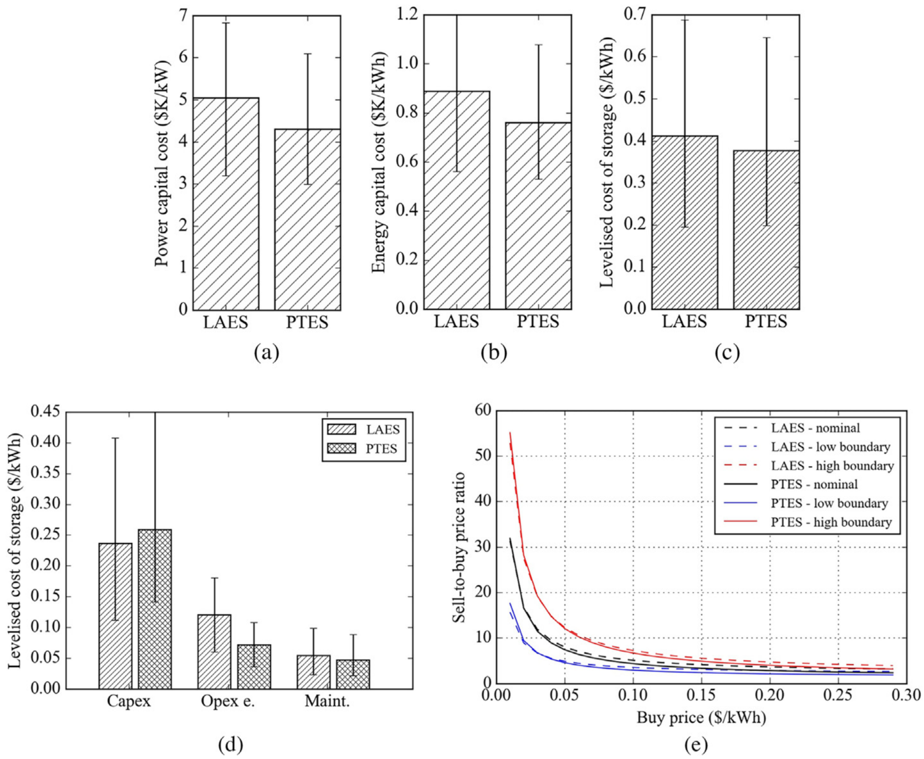

Fig. 16. Results for LAES and PTES systems at equal capacities (2 MW, 11.5 MWh): (a) power capital cost, (b) energy capital cost, and (c) levelised cost of storage. (d) Levelised cost of storage (LCOS) per expenditure category (Capex: capital expenditure, Opex e.: operational expenditure for energy, Maint.: maintenance costs). (e) Comparison between LAES and PTES in terms of required sell-to-buy price ratio against the electricity buying price. The error bars and high-low bounds indicate the variations (min-max) obtained when using the different costing methods in Section 3 and the variability associated with the uncertainty factors where applicable.

essentially the case for the other two elements of LCOS. This can be due to the potential cost trade-off associated with the incorporation of more expensive equipment that might be required for an insignificant increase in efficiency, for instance as a result higher operating pressures.

Furthermore, to analyse the financial feasibility of the systems over their lifetimes, another important and insightful economic metric relevant to energy storage technologies is the sell-to-buy (STB) price ratio necessary for the system to become financially feasible. The terms sell price (SP) and buy price (BP) refer to the electricity price during peak and off-peak electricity demands respectively. Therefore, the ratio between SP and BP determines the STB. Here, the system is classified as financially feasible at the break-even point which is considered to be when the net present value (NPV), which takes into consideration finance costs, capital expenditure, operational costs and incomes, is equal to zero while assuming equal annual benefits over the lifetime of the system. Therefore, for each of the two systems to become financially feasible, the required minimum STB ratio was determined based on the variation of BP (shown in Fig. 15), where any operating point at an STB ratio over the curve can be characterised as financially feasible.

Both system curves show a similar trend with a monotonic decrease that is sharp at lower BPs and shallower at BPs over ~0.20 $/kWh, which is mainly due to the fact that at higher BPs the operational energy costs become the dominant cost of each system relative to capital costs and maintenance costs; thus the required STB ratio is driven mainly by the roundtrip efficiency of each system. Therefore, the required STB ratio becomes increasingly independent from the other cost factors. Specifically, at the lower end of BPs considered here, LAES shows a lower required STB ratio than PTES with the difference between the two decreasing as the BP increases. Above a BP value of about 0.15 $/kWh, PTES appears to become the most financially competitive of the two, although the difference between the two STB ratios is small at higher BPs; specifically, this difference over the crossover point of 0.15 $/kWh grows slightly in the mid-range of BP values and then remains relatively constant towards the high end of the range considered here.

Furthermore, another interesting observation concerns the substantially greater uncertainty in the required STB ratio affiliated with low BP values compared to that at higher values. Consequently, at higher BP values both systems are found to be more robust in terms of required STB ratio in the market place. Since the two main elements of uncertainty in this analysis, apart from capital costing, are now the maintenance costs and discount rate (given that the uncertainty in energy costs is the varying parameter here), this plot also captures the effect of these factors on the financial feasibility of the systems. These factors were observed to have a slightly greater impact on PTES primarily due to the greater share of the total costs associated with capital expenditure compared to the LAES system.

4.3. Thermo-economic analysis at equal capacities

It is recognised that the analysis performed earlier focused on the capacities of each technology as intended for commercial application and that the two systems were of significantly different size and scale. Therefore, in this section we present a like-for-like comparison between the two systems at the same power, energy and charging capacities. The rated power output and energy capacities adopted here are 2 MW and 11.5 MWh, respectively, thus effectively considering a LAES plant at the same scale as the PTES considered earlier. This decision was made as it was deemed more straightforward to envisage a technically feasible LAES plant of such reduced size, than a PTES plant of an increased size given the components considered in the implementation of the latter, and in particular the reciprocating compression and expansion machines. It is anticipated that at this scale the two systems, LAES which is intended for use at much higher capacities, might be at a disadvantageous, and hence the earlier results presented for its intended implementation capacity are expected to be more representative of a large-scale commercial LAES system.

In contrast to the results presented in Section 4.2, LAES at this smaller capacity is estimated to have higher average power and energy capital costs, and a higher average LCOS with values of 5.05 $K/kW (PTES: 4.30 $K/kW), 0.89 $K/kWh (PTES: 0.76 $K/kWh) and 0.41 $/kWh (PTES: 0.38 $/kWh). Results relating to all three performance indicators are shown in Fig. 16a–c. The differences, however, between the two systems in terms of these costs is smaller than the differences observed at their intended implementation capacities described in Section 4.2. Furthermore, a significantly greater cost variability is noted in the values of LAES in comparison to their corresponding values at its nominal capacity.

Similar to estimates at nominal capacities, the LCOS allocated to capital expenditure was observed to be greater for PTES than LAES, as well as the allocated cost to operational energy cost to be greater for LAES than PTES (see Fig. 16d). However, even though the difference between the two systems in allocated operational energy cost remains similar, the difference in LCOS allocated to capital expenditure was noted to be much smaller due to the significant increase of LAES. Thus, this represents the main driver for the increase in average LCOS of LAES to a higher level than PTES.

Different from the results at nominal capacities, the required sell-to-buy price ratio was observed to be very close for both systems at low BP values ($\sim < 0.03$ \$/kWh) with PTES becoming slightly more competitive than LAES at BPs close to ~ 0.02 \$/kWh (see Fig. 16e). The difference between the two systems grows slightly from a BP of 0.02 \$/kWh towards higher values, and then remains relatively stable towards the high end of BPs considered. Following from the observation earlier that the increase in average LCOS of LAES was mainly due to capital expenditure, the greatest impact on LAES at the lower end of BPs as opposed to higher BPs at which operational energy costs become the dominant cost factor, is justified. Nevertheless, both systems follow a similar trend to the one observed at their nominal capacities with a sharp monotonic decrease at lower BPs and shallower at higher BPs.

5. Conclusions

Models of two newly proposed medium- to large-scale bulk electricity storage systems, namely 'Pumped-Thermal Electricity Storage' (PTES) and 'Liquid-Air Energy Storage' (LAES), were developed to allow for a thermo-economic comparison between these technologies focusing on roundtrip efficiency and costs. To the best of the authors' knowledge, a direct comparison of these interesting early-stage technologies simultaneously from thermodynamic, industrial operation and economic perspectives is currently lacking in the literature.

In general, the two systems were observed to be competitive against each other from a thermo-economic perspective while factors affecting their competiveness were noted. PTES achieved higher roundtrip efficiencies than LAES at the configurations and conditions examined, while operating pressures were found have a strong impact on its roundtrip efficiency, especially at low pressure ratios. The LAES system's roundtrip efficiency was found to be strongly dependent in the quantity of waste-cold recycled and utilised during the liquefaction stage in the charge cycle, and the temperature of the waste-heat delivered during the power generation stage in the discharge cycle. The appropriate utilisation of these two elements represents a significant opportunity to support the competitiveness of LAES technology against other bulk electricity storage technologies such as compressed-air energy storage, pumped hydro storage as well as PTES. LAES technology also has an advantage over PTES in terms of maturity/readiness, as the technology employs readily available equipment and it has been experimentally proven at pilot-plant scale.

From an economic perspective, the initial capital cost of both systems was found to be dominated by equipment involving power output/input (i.e., expanders/turbines and compressors). LAES was found to be lower-cost overall in terms of the power capital cost and energy capital cost. However, in terms of levelised cost of storage (LCOS) and minimum required sell-to-buy (STB) price ratio, the two technologies were found to be similar to each other, with PTES perhaps (by a small margin) becoming more competitive than LAES over a buy price of ~ 0.15 \$/kWh. Nonetheless, for both PTES and LAES, the buying price (BP) of electricity was found to have a significant effect on the minimum required STB ratio at low BPs, with the required ratio diminishing as BP increases due to operating energy costs becoming dominant over other cost factors (capital expenditure, maintenance costs).

The two systems, LAES and PTES, were also compared at equal capacities even though this potentially means that LAES was analysed at significantly lower than intended capacities. At this size, power capital cost, energy capital cost and LCOS for LAES were estimated to be slightly higher than PTES; as opposed to the estimates at nominal capacities. Furthermore, the minimum required STB ratios of LAES and PTES were observed to be very similar at the lower end of BPs with PTES becoming slightly more competitive at lower BPs than before.

Finally, in terms of competiveness against other technologies, the power capital cost at nominal capacities of LAES and PTES was compared against those of existing technologies based on literature data. While it is expected that both LAES and PTES will improve relative to competing technologies as their maturity and readiness levels develop, and bearing in mind that LAES and PTES have certain characteristics that allow them to be employed in applications where few competing technologies are intended to function, it was promising to observe that in terms of power capital cost LAES was already found to be more competitive than a variety of existing technologies.

Further work could include the application of learning curves, applicable to such novel technologies, in order to project their competitiveness against existing/mature and other early-stage alternative technologies. The effect of learning curves is expected to depend on the room for improvement of each technology in terms of both performance and cost. This presents another interesting aspect for further investigation. Furthermore, approximate cost estimates are presented in the present study based on a simplified approach which assumes that equipment can be used for the construction of the systems of interest whose costs can be captured accurately by the standard correlations used in this work. As the maturity of these systems increases, it is expected that more information will be available and that the cost estimates can be further refined. Finally, the scalability of the technologies to other capacities and the variation of power to energy storage capacities can introduce a variability in the economic estimations that would be interesting to investigate.

Acknowledgments

This work was supported by the UK Engineering and Physical Sciences Research Council (EPSRC) [grant numbers EP/J006041/1 and EP/P004709/1] and UK Natural Environment Research Council (NERC) [grant number NE/L002515/1]. The authors would also like to acknowledge the Science and Solutions for a Changing Planet DTP. Data supporting this publication can be obtained on request from cep-lab@imperial.ac.uk.

References

[1] Markides CN. The role of pumped and waste heat technologies in a high-efficiency sustainable energy future for the UK. Appl Therm Eng 2014;53(2):197–209.
[2] Markides CN. Low-concentration solar-power systems based on organic Rankine cycles for distributed-scale applications: Overview and further developments. Front Energy Res 2015;3(47):1–16.
[3] Mariaud A, Acha S, Ekins-Daukes N, Shah N, Markides CN. Integrated optimisation of photovoltaic and battery storage systems for UK commercial buildings. Appl Energy 2017;199:466–78.
[4] Freeman J, Hellgardt K, Markides CN. An assessment of solar-powered organic Rankine cycle systems for combined heating and power in UK domestic applications. Appl Energy 2015;138:605–20.
[5] Freeman J, Hellgardt K, Markides CN. Working fluid selection and electrical performance optimisation of a domestic solar-ORC combined heat and power system for year-round operation in the UK. Appl Energy 2017;186:291–303.
[6] Herrando M, Markides CN, Hellgardt K. A UK-based assessment of hybrid PV and solar-thermal systems for domestic heating and power: System performance. Appl Energy 2014;122:288–309.
[7] Guarracino I, Mellor A, Ekins-Daukes NJ, Markides CN. Dynamic coupled thermal-and-electrical modelling of sheet-and-tube hybrid photovoltaic/thermal (PVT)

collectors. Appl Therm Eng 2016;101:778–95.
[8] Ramos A, Chatzopoulou MA, Guarracino I, Freeman J, Markides CN. Hybrid photovoltaic-thermal solar systems for combined heating, cooling and power provision in the urban environment. Energy Convers Manag 2017;150:838–50.
[9] Strbac G, Aunedi M, Pudjianto D, Djapic P, Teng F, Sturt A, et al. Strategic assessment of the role and value of energy storage systems in the UK low carbon energy future. London (UK): Imperial College London, Energy Futures Lab; 2012.
[10] 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(3):291–312.
[11] Georgiou S, Mac Dowell N, Shah N, Markides CN. Thermo-economic comparison of liquid-air and pumped-thermal electricity storage. In: ECOS 2017: Proceedings of the 30th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems, July 2–6. San Diego (USA); 2017.
[12] Highview Power Storage. Liquid Air Energy Storage 2016 < http://www.highview-power.com > [accessed 15.2.2016].
[13] Centre for Low Carbon Futures, Liquid air in the energy and transport systems: opportunities for industry and innovation in the UK. York, UK: Centre for Low Carbon Futures; 2013 May. Report No. 021.
[14] Morgan R, Nelmes S, Gibson E, Brett G. Liquid air energy storage – analysis and first results from a pilot scale demonstration plant. Appl Energy 2015;137:845–53.
[15] Sciacovelli A, Smith D, Navarro H, Li Y, Ding Y. Liquid air energy storage – operation and performance of the first pilot plant in the world. In: ECOS 2016: Proceedings of the 29th international conference on efficiency, cost, optimization, simulation and environmental impact of energy systems; 2016 June 29–23; Portorož, Slovenia.
[16] 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.
[17] White A, Parks G, Markides CN. Thermodynamic analysis of pumped thermal electricity storage. Appl Therm Eng 2013;53(2):291–8.
[18] McTigue JD, White AJ, Markides CN. Parametric studies and optimisation of pumped thermal electricity storage. Appl Energy 2015;137:800–11.
[19] White AJ, McTigue JD, Markides CN. Analysis and optimisation of packed-bed thermal reservoirs for electricity storage applications. Proc Inst Mech Eng Part A:J Power Energy 2016;230(7):739–54.
[20] White A, McTigue J, Markides C. Wave propagation and thermodynamic losses in packed-bed thermal reservoirs for energy storage. Appl Energy 2014;130:648–57.
[21] Frate GF, Antonelli M, Desideri U. A novel Pumped Thermal Electricity Storage (PTES) system with thermal integration. Appl Therm Eng 2017;121:1051–8.
[22] Roskosch D, Atakan B. Pumped heat electricity storage: potential analysis and ORC requirements. Energy Proc 2017;129:1026–33.
[23] 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.
[24] Sandria National Laboratories. DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA. New Mexico and California (USA): Sandria National Laboratories; 2013 July. Report No. SAN2013-5131.
[25] Jülch V. Comparison of electricity storage options using levelized cost of storage (LCOS) method. Appl Energy 2016;183:1594–606.
[26] Obi M, Jensen SM, Ferris JB, Bass RB. Calculation of levelized costs of electricity for various electrical energy storage systems. Renew Sustain Energy Rev 2017;67:908–20.
[27] Benato A. Performance and cost evaluation of an innovative Pumped Thermal Electricity Storage power system. Energy 2017;138:419–36.
[28] 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.
[29] 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.
[30] Thess A. Thermodynamic efficiency of pumped heat electricity storage. Phys Rev Lett 2013;111(11):110602. 1–5.
[31] Lemmon EW, Huber ML, McLinden MO. NIST standard reference database 23: Reference fluid thermodynamic and transport properties-REFPROP, Version 9.1. Gaithersburg: National Institute of Standards and Technology, Standard Reference Data Program; 2013.
[32] Shilling RL, Bell KJ, Bernhagen PM, Flynn TM, Goldschmidt VM, Hrnjak PS, et al. Heat-transfer equipment. In: Perry RH, Green DW, Maloney JO, editors. Perry's chemical engineers' handbook, 7th ed. McGraw-Hill; 1997. p. 11.1–118.
[33] White AJ. Loss analysis of thermal reservoirs for electrical energy storage schemes. Appl Energy 2011;88:4150–9.
[34] Turton R, Bailie RC, Whiting WB, Shaeiwitz JA. Analysis, synthesis and design of chemical processes, 4th ed. London (UK): Pearson Education International; 2013.
[35] Jenkins S. Economic indicators: CEPCI. Chemical engineering essentials for the CPI professional < http://www.chemengonline.com/economic-indicators-cepci > [accessed 5.11.2016].
[36] Seider WD, Seader JD, Lewin DR, Widagdo S. Product and design principles: synthesis analysis, and evaluation, 3rd ed. Asia: John Wiley & Sons (Asia) Pte Ltd; 2010.
[37] Couper JR, Penney WR, Fair JR, Walas SM. Chemical process equipment: selection and design, revised second ed. MA (USA): Butterworth-Heinemann, Elsevier Inc.; 2010.
[38] Lemmens S. Cost engineering techniques and their applicability for cost estimation of organic Rankine cycle systems. Energies 2016;9(7):485.
[39] Hewitt GF, Pugh SJ. Approximate design and costing methods for heat exchangers. Heat Transf Eng 2007;28(2):76–86.
[40] Holman JP. Experimental methods for engineers, 8th ed. NY (USA): McGraw-Hill Connect Learn Succeed; 2012.
[41] Energy Storage Association (ESA) < http://energystorage.org/ > [accessed 10.10. 2017].
[42] Denholm P, Ela E, Kirby B, Milligan M. The role of energy storage with renewable electricity generation. Colorado (USA): National Renewable Energy Laboratory; 2010 Jan. Report No. NREL/TP-6A2-47187.
[43] Steinbach J, Staniaszek D. Discount rates in energy system analysis [discussion paper]. Belgium: Buildings Performance Institute Europe (BPIE); 2015 May.
[44] Energy Solutions. Historical Electricity Prices < http://www.energybrokers.co.uk > [accessed 10.12.2016].