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Techno-economic analysis of bulk-scale compressed air energy storage in power system decarbonisation

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ABSTRACT

Although the penetration of renewable energy in power systems has been substantially increased globally in the last decade, fossil fuels are still important in providing the essential flexibility required to reliably maintain the system balance. In 2019, more than one quarter of power generation in Europe and over 40% of the UK's electricity generation was from fossil fuels (mainly gas). For achieving the net-zero greenhouse gas emission target around the middle of this century, these fossil fuels have to be decarbonised in the coming decades. Bulk-scale energy storage has been recognised as a key technology to overcome the reduced dispatchability associated with the decrease of fossil fuels in generation. Taking the UK power system as a case study, this paper presents an assessment of geological resources for bulk-scale compressed air energy storage (CAES), and an optimal planning framework for CAES in combination with solar and wind to replace fossil fuels in the power generation system. The analysis reveals up to 725 GWh of ready-to-use capacity by utilising existing underground salt caverns in the UK. These potential CAES sites with added solar and wind generation equal to the generation from fossil fuels in 2018 can reduce carbon emissions by 84% with a cost increase by 29%, compared to the system in 2018. The results indicate the plausibly achievable cost-effectiveness of CAES as bulk-scale energy storage for power system decarbonisation in countries the geological resources are available.

1. Introduction

Renewable energy has been mostly rapidly deployed for power generation among all energy resources in the last decade. According to the data from International Renewable Energy Agency, from 2009 to 2018, the installed power capacity from renewable energy sources increased from about 1.1 TW to 2.4 TW in which the power capacity of solar and wind increased by almost tenfold from ~0.1 TW to more than 1 TW [1]. In 2018, renewable energy accounted for 75% of the newly installed worldwide power capacity [2]. However, due to the nature of intermittent renewable energy sources (e.g. solar and wind), flexibility is increasingly challenging for power system operators to ensure the balance between supply and demand in power systems. To achieve that, fossil fuels are still playing an essential role to offer the flexibility that can address the intermittency of renewable energy sources. In 2019, more than 25% of power generation in Europe is from fossil fuels in which 22% is from gas [3]. In the UK, about 40% of the electricity is generated from gas fired power plants, providing the significant balance service [4]. To meet the net-zero emission goal around the mid-21st century set in the Paris Agreement [5], these power plants have to be decarbonised or mostly replaced by other low-carbon technologies in the near future [6].

Bulk-scale, or grid-scale, energy storage has been acknowledged as an essential technology to tackle the challenges in deep decarbonisation with large-scale renewable power when the use of fossil fuels is reduced [7]. Although lithium-ion batteries and hydrogen are often recognised as promising candidates for power decarbonisation in various modelling studies [6,8,9], they may still require multiple years of research and development before reaching a cost-effective point or a satisfactory technology readiness level for commercial roll-outs as bulk-scale energy storage. Lithium-ion batteries are not currently cost effective for energy storage operation at timescales larger than 1-day, even with a significantly reduced cost in future (e.g. $150/kWh) [10,11]. Additionally, the management and decommissioning of lithium-ion batteries at end-of-life needs a great research effort to tackle the recycling challenge caused by the rapidly growing market [12]. Furthermore, hydrogen energy storage is still in its research phase, and its cost reduction may require significant infrastructure construction (e.g. centralised electrolysis) [13,14], and the use of less mature but promising technologies (e.g. high-temperature solid oxide or molten

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Nomenclature

B_p	Exergy storage capacity contributed by the enhanced pressure [J]
B_T	Exergy storage capacity contributed by the enhanced temperature [J]
$\dot{M}_{CO2,l}$	Carbon intensity [$kgCO_2$/MWh]
c^E_{CAES}	Annualised fixed cost per energy capacity [$/MWh]
$W_{i,c}$	Power consumption of the compressor at stage i [W]
c^p_{CAES}	Annualised fixed cost per power capacity [$/MW]
η_c	Compressor efficiency [%]
η_{cycle}	Cycle efficiency [%]
η_e	Expander/turbine efficiency [%]
η_g	Generator efficiency [%]
η_m	Motor efficiency [%]
E_n	Storage power capacity [MWh]
E^y_d	Annual energy demand [MWh]
$E^y_{g,l}$	Individual annual generation of the energy source l [MWh]
l	Individual energy source
$W_{j,e}$	Power consumption of the expander/turbine at stage j [W]
γ	Isentropic index
R	Gas Constant [J/(kgK)]
$g_{gas,t}$	Power dispatching of gas power [MWh]
r	Interest [%]
N	Lifetime [year]
o_{CAES}	Variable cost during operation of the storage [$/MWh]
o_{gas}	Operating cost of gas [$/MWh]
$[h_{n,t}]^+$	Power dispatching during the charging [MWh]
P_{gen}	Total power generation timeseries
P_{other}	Power generation timeseries from other power sources
P_{solar}	Solar power generation timeseries
P_{wind}	Wind power generation timeseries
H_n	Storage power capacity [MW]
p	Air Pressure [Pa]
j	The stage number in expansion
i	The number of stage in compression
T	Air Temperature [K]
V	Air Volume [m^3]
w_{solar}	generation factor of solar
w_t	Weight coefficient
w_{wind}	generation factor of wind

Abbreviations

A-CAES	Adiabatic Compressed Air Energy Storage
CAES	Compressed Air Energy Storage
CapEx	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
HEX	Heat Exchanger
LCOE	Levelised Cost of Electricity
LCOUE	Levelised Cost of Utilised Electricity
mcm	million cubic meters
OCGT	Open Cycle Gas Turbine
OpEx	Operational Expenditure
PHS	Pumped Hydro Storage
TES	Thermal Energy Storage

carbonate fuel cells) [15]. As cumulative carbon emissions in the atmosphere have already severely tightened the future carbon budget [16], any early opportunities to affordably and effectively reduce emissions from now rather than years later deserve attention [17].

In this context, Compressed Air Energy Storage (CAES) is currently the only commercially mature technology for bulk-scale energy storage, except Pumped Hydro Storage (PHS) [18]. A CAES system refers to a process of converting electrical energy to a form of compressed air for energy storage and then converting it back to electricity when needed [19]. CAES has low storage costs per unit energy (i.e. $/kWh) and negligible self-discharging, making it suitable for large-scale long-duration storage [20], which could significantly outperform electrochemical storage such as lead-acid batteries or lithium batteries for maximising the value of bulk-scale storage-integrated renewable generation [21]. It could also be an inter-seasonal storage (e.g. 77–96 TWh using UK saline aquifers, about 160% of the national electricity consumption for January and February) with a relatively low levelised cost of storage ($0.42–4.71/kWh) [22].

Compared to electrochemical storage (e.g. lithium-ion batteries), CAES has a lower energy density (3–6 kWh/m^3) [20], and thus often uses geological resources for large-scale air storage. Aghahosseini et al. assessed the global favourable geological resources for CAES and revealed that resources for large-scale CAES are promising in most of the regions across the world, particularly abundant in North and South America and Sub-Saharan Africa [23]. The analysis indicates that about 6,574 TWh storage capacity is available if less than 5% of the global geological potential for CAES is used [23]. This energy capacity is about 30% of the total current global electricity consumption [24]. Utilising these resources for CAES could significantly boost the current storage capacity in the world (~5 TWh [25]), enabling the power system to integrate increasingly more solar and wind power for power decarbonisation

Among CAES technologies, adiabatic CAES (A-CAES) is the most investigated technology in the last decade, because of its emission-free nature and the suitability for bulk-scale applications (i.e. over 100 MWh) [19]. To improve and demonstrate the performance of A-CAES systems, previous studies have focused on the model development [26], performance improvements of components [27,28], multi-physics coupling between components [29], system optimisation [30], new operations [31] and pilot system demonstrations [32–35]. Compared to the system performance improvement, there are fewer studies that focus on the scheduling strategy of A-CAES. Drury et al. evaluated the value of A-CAES for providing operating reserves in addition to energy arbitrage in several US markets [36]. Li et al. investigated the operational strategy of A-CAES for optimising energy and reserve scheduling [37] and providing emergency back-up power to support microgrid operation [38]. Khatami et al. proposed novel look-ahead optimisation models for CAES participation in day-ahead and real-time electricity markets [39]. Bai et al. proposed a tri-state model of A-CAES that considers its part-load characteristics and applied the model to the A-CAES's scheduling [40], aiming at optimising its operation with linked dynamics over varied operations. Li et al. investigated a micro grid system and optimised the scheduling of a CAES system for heating, cooling, and electricity, in coordination with the power distribution network, and district heating network [41].

From the literature, it is noticed that prior studies of A-CAES focus on the technological development for improving storage performance or optimal scheduling of A-CAES in one or more specified electrical markets or micro-grid systems. As a promising technology for bulk-scale energy storage, there is a significant knowledge gap in evaluating the potential of CAES using available geological resources for the national-scale power system decarbonisation. Moreover, as a bulk-scale energy storage that usually uses geological resources, CAES requires large upfront capital investments, due diligence in geological surveys for site selection, and site-based system design and operation. As a consequence, these factors result in an extended planning stage and complex long-term economics [42], posing uncertainties in the techno-economic role of CAES as a low-cost bulk-scale energy storage technology in approaching affordable energy decarbonisation. Compared to short-term energy storage projects, such as lithium-ion batteries, thus far the optimal planning of bulk-scale storage projects is poorly understood, due to their uncertain economics over their much longer lifetime spans. This is another significant knowledge gap, which may jeopardise the planning and development of CAES to provide large-scale and long-duration storage for deeply decarbonising power systems.

Therefore, the contribution of this study is to use real geographic datasets of underground salt-caverns in combination with power system operational data to techno-economically analyse the plausibly achievable potential of cavern-based CAES for a national-scale power decarbonisation, exploring the cost-effectiveness of CAES as bulk-scale energy storage for reducing carbon emissions of the whole power system. This paper investigates the technical potential and economic cost of using solar, wind, and CAES to meet electrical demand in a national-scale power system while reducing the carbon emissions as much as possible. Given the low-cost of CAES and its gigantic potential storage capacity worldwide, an improved understanding of the CAES's technical performance and economic costs could underline affordable power decarbonisation worldwide. To fulfil the knowledge gap, in this study, using the UK power system as a case study, the role and cost of CAES in the deep decarbonisation of the power system is elucidated by exploring three questions surrounding the adoption of solar, wind, and CAES as a replacement of the flexible power currently provided by fossil-fuels, including gas and coal, for the system balance: (a) how much is the energy capacity for CAES and where could these plants be built? (b) what are the optimal power capacities and temporal dispatching patterns (i.e. charging and discharging) of CAES to minimise the low-carbon power system cost? (c) does a combination of solar, wind, and CAES have the potential to cost-effectively replace current gas power plants?

The paper is organised as follows: to highlight the three identified research questions, Sections 2, 3, and 4 present results respectively as answers using the methodology given in Appendix. Specifically, in Section 2, the potential storage sites and energy storage capacities are presented. Section 3 conducts a scenario analysis of the UK system with different renewable power penetration and storage capacity for investigating the role and costs of CAES for power system decarbonisation. Section 4 presents the cost analysis in decarbonising the power system by using solar, wind, and bulk-scale CAES systems. Finally, in Section 5, various influential factors including policy-making, technologies, and market design are discussed for the purposes of enabling a rapid growth of bulk-scale energy storage.

2. How much is the energy capacity for CAES and where could these plants be built?

To answer the question, the existing underground gas storage facilities that could be purposed for air storage in CAES are assessed. Using the UK system as an example, Fig. 1 shows current gas power plants [43], existing underground gas storage facilities [44,45], and transmission networks. Most gas power plants in the UK are Combined Cycle Gas Turbine (CCGT) that are gas turbine systems combined with the steam turbines. CCGT plants have around 32 GW of generating capacity [43]. Other gas power plants (about 2 GW) are Open Cycle Gas Turbine (OCGT) plants that are simple gas turbine systems mainly providing electricity to meet peak electrical demands due to their fast start-up and flexible operation [43]. In 2018, the total electricity generation from gas power in the UK was about 116 TWh (CCGTs provide more than 99.9% of the generated electricity) based on data from GridWatch [4]. Using the referenced carbon intensity 710 $kgCO_2$/MWh and 405 $kgCO_2$/MWh for estimating the CO_2 emissions of OCGT and CCGT respectively [17], the total carbon emissions due to gas powered electricity generation are about 47 $MtCO_2$. In addition to the generation from coal, which is about 15 TWh with a considered 1025 $kgCO_2$/MWh carbon intensity [17], the estimated total emission due to the fossil-fuel based power system is about 63 $MtCO_2$, very close to the total power system carbon emission reported (~65 $MtCO_2$) by the government [46].

CAES has a wide range of underground storage options [45]. Table 1 summarises the UK's existing and under construction salt cavern gas storage facility's design and operational parameters, and shows that the country has an underground storage volume of ~66.53 million cubic meters (mcm), most of which are salt caverns [44]. Presently, the main purpose of these facilities is for storage of natural gas. Therefore, these storage facilities have access to the gas network, connecting with gas power plants which have access to the electricity transmission network.

These gas storage facilities provided about 6.5% of the total UK gas supply in winter between 2008 to 2012 [47], including power and heating usage. When the energy system is further decarbonised, the demand from natural gas will decrease, potentially allowing some of these facilities to be used for other purposes. In addition, these underground caverns are a good representation of the UK geological resources for gas storage, indicating the storage conditions (e.g. pressure range) that the future underground caverns may have. Because these salt cavern storage facilities can handle frequent cycles, high injection and withdrawal gas flow rates, and have a lower share of cushion gas [44], underground salt caverns that are mined with mature technologies are inexpensive storage units for compressed air. Therefore, in this study, these underground gas storage facilities are employed as useable air stores to conduct the national-scale analysis of power decarbonisation.

Due to importance for strategic energy reserve, it is unlikely that all existing natural gas storage facilities will be converted for compressed air storage. However, geological resources for additional salt caverns are abundant and can thus provide additional storage facilities for both natural gas and CAES.

Fig. 1b shows UK's salt-deposit basins in which new underground gas storage facilities can be potentially excavated in the future if more electricity storage (e.g. volume for storing compressed air or other gases) is needed. The Zechstein salts (in which the Huntorf CAES caverns, the first commercial CAES plant in the world, are based) and the Mesozoic and Cenozoic salts in East Yorkshire and Southern North Sea can provide new caverns onshore and offshore. Additionally, potential salt deposits could be in the onshore Triassic salt beds of the Northwich Halite Member in Cheshire, the Permian salt beds in eastern and north-eastern England, salt beds of the Triassic Preesall Halite in the East Irish Sea, Permian salt beds onshore in the Islandmagee area of North Ireland, and salt-bearing Triassic mudstones in Celtic Sea's basins and Bristol Channel basins [44]. In the Cheshire Basin, only 1% of the current available salt can support more than 100 new storage facilities, each of which contains ~16 caverns with 100 m height [44]. With a random subset of 10 caverns in the Cheshire Basin, a ~25 GWh electrical storage capacity was estimated [48], indicating a potential storage capacity at least in the order of terawatt-hours in the Cheshire Basin alone. Besides salt caverns, other resources for gas storage, including aquifers and gas fields, are also substantial [22,47]. Therefore, potential for planning and building new CAES plants or other technologies that are in competition for the resources are available in the country.

Furthermore, using the geological parameters of the UK's existing and under construction gas storage facilities (as listed in Table 1) and the thermodynamic analysis method that estimates the theoretical maximum storage capacity (see Appendix), site-based system performance,

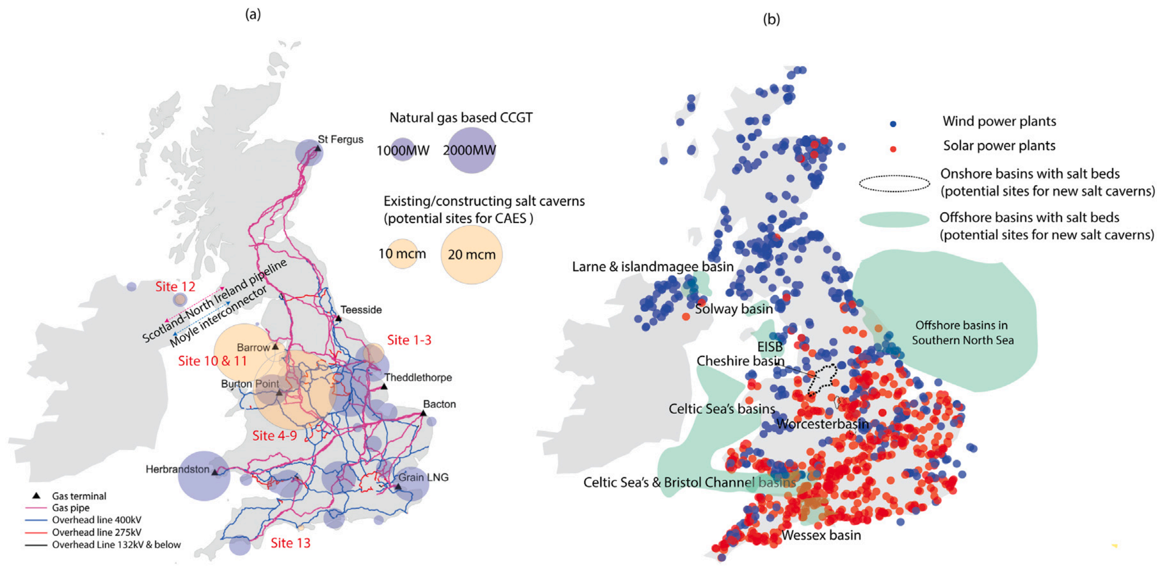

Fig. 1. Gas power, solar, and wind generation and existing and potential underground gas storage facilities in the UK. Figure (a) plots the existing gas power and underground storage facilities. Figure (b) plots the geological resources for underground gas storage and current solar and wind generation.

Table 1
Summary of UK salt cavern gas storage facility geological and Operational parameters. Hole House (a gas storage site) is not considered in this study as there is not data available for the site. *The minimum storage pressure of the site (King street energy) is not available, so an assumed minimum pressure was used in the analysis.

Site No.	Site name	Status	Pressure range [$\times 10^5$Pa]	Physical volume [$\times 10^6$ m^3]
1	Horsea	Operational	120–270	~1.98
2	Aldbrough I	Operational	120–270	~2.43
3	Whitehill	constructing	100–345	~2.5
4	Holford H165	Operational	70–85	0.175
5	Hilltop Farm/Hole	Operational	29–45	~6.25
6	Holford	Operational	40–105	~2.9
7	Stublach	Operational	30–101	~6.6
8	King street energy	constructing	33*-66	~5.5
9	Keuper has storage	constructing	43.8–123	~5.97
10	Gateway	constructing	36–120	~20
11	Preesall	constructing	33–92	~6.8
12	Islandmagee	constructing	120–250	~3.36
13	Portland	constructing	2–240	~2

namely electrical energy capacity and cycle efficiency, were estimated. The results are plotted in Fig. 2.

Fig. 2 shows that UK has an estimated potential of up to 725 GWh electrical storage capacity of CAES if the current underground salt-mined caverns are operated at the upper and lower limits of the caverns' allowable pressure for air storage. The largest electrical storage capacity is provided by the (under construction) Gateway gas storage facility, which could provide up to about 200 GWh of electricity capacity using CAES. The potential maximum electricity storage of CAES using existing salt caverns is up to 26 times the UK's current storage capacity of PHS (~27.6 GWh in total [49]), and close to the recently estimated electrical energy storage capacity (~950 GWh including PHS) required for the 80% CO_2 reduction goal [50].

To estimate the site-based cycle efficiency, an A-CAES configuration that uses pressurised water as thermal energy storage was considered. The A-CAES configuration with hot water (see Appendix) is a well-developed and -demonstrated adiabatic CAES technology, ready for commercial roll-outs [32,34,51]. Although other adiabatic CAES configurations (e.g. CAES with high-temperature thermal storage or traditional diabatic CAES technology in the same manner as Huntorf/McIntosh) may have higher energy efficiencies or lower Capital Expenditure (CapEx) than the water-integrated A-CAES, this system architecture with demonstrated satisfactory performance at the scale ~10 MW in the field can plausibly enable a reduced time for planning and construction of CAES plants and reducing carbon emissions.

Using the thermodynamic model of CAES (see Appendix), the cycle efficiency of all potential CAES sites was assessed, the results of which are plotted in Fig. 2b. As the underground storage has different geological conditions, the cycle efficiency varies between storage sites, which is in a range of 56%–70%. These obtained cycle efficiencies are close to the recently demonstrated pilot systems, namely 60.2% of the 10 MW A-CAES in China [34] and 72% of the 1 MWh system in Switzerland [33].

3. What are optimal power capacity and temporal dispatching patterns (i.e. charging and discharging) of CAES to minimise the power system cost?

The temporal operating patterns of the potential CAES plants are obtained by conducting a power flow optimisation, which aims to minimise the power system cost by adjusting the power system control variables while satisfying various equality and inequality constraints. The equality constraints are the power balances at each temporal snapshot (i.e. balance between generation, demand, and storage), and the inequality constraints are usually determined by the limiting capacities of components in the power system (e.g. generation at any snapshot is less than the maximal generation capacity).

With the electrical energy capacities (as shown in Fig. 2a), as well as the site-based cycle efficiencies (as shown in Fig. 2b) estimated above, the optimal power flow model of the power system with potential

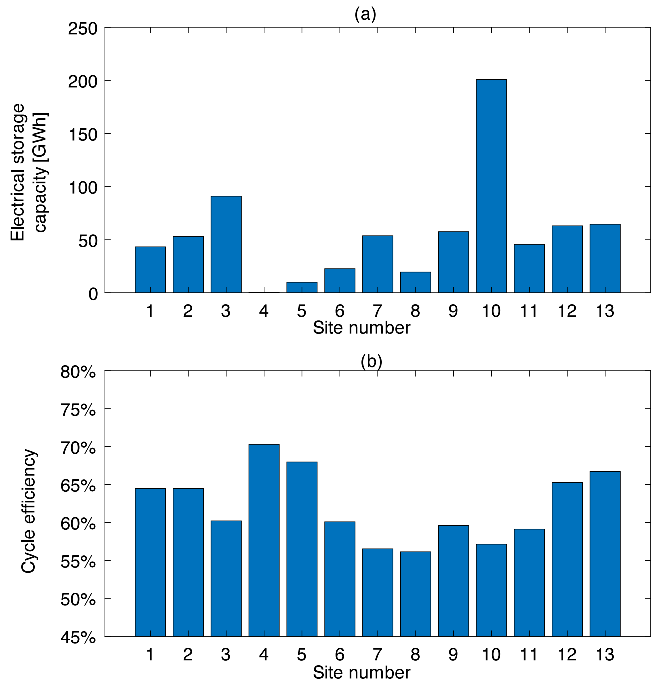

Fig. 2. Site-based electrical storage capacity in (a) and cycle efficiency in (b) of the potential CAES plants.

CAES plants was built and the optimisation was conducted accordingly (see Appendix). The optimal power flow model allows the simulation and optimisation of both power capacity (i.e. rated charging and discharging power) and temporal dispatching of generation and storage for minimising the total power system cost including both CapEx and Operational Expenditure (OpEx).

Three system scenarios are considered:

- system a: The UK power system in 2018. Using data from Gridwatch [4], the total power generation in 2018 was about 281 TWh, including CCGT (116 TWh, 41%), OCGT and oil-based engines (18 GWh, <0.01%), solar (11 TWh, 4%), wind (39 TWh, 14%), hydro (3 TWh, 1%), nuclear (61 TWh, 22%), biomass (16 TWh, 6%), coal (15 TWh, 5%), and power from interconnections (20 TWh, 7%). The total electrical demand was 275 TWh, which is about 98% of the total power generation. It should be noted here that PHS is not considered in the generation, although the PHS plants generated about 3 TWh of electricity to meet the demand in 2018.
- system b: A low-carbon UK power system with gas power as a flexible generation if needed, but no storage. It was assumed that the low-carbon power system has added 131 TWh from solar and wind power (the total annual generation is same to the total annual generation from fossil fuels in 2018), aiming to reduce the use of gas or coal. This added solar and wind generation is about 2.6 times the current annual generation of solar and wind in 2018. The solar and wind power is assumed to be added by proportionally increasing the power by 2.6 times at each time snapshot over a whole year. In this case, the total generation of system b without fossil fuels is same to the total power generation of system a (i.e. 281 TWh). Gas power can be used to generate electricity for meeting the electrical demand when the low-carbon power is not sufficient at any temporal snapshots.
- system c: A low-carbon UK power system with CAES, and gas power as a flexible generation if needed. The system has the same power generation as system b in which increased solar and wind power generation is considered. CAES plants using the 13 potential underground gas storage facilities are connected to this power system, with the potential electricity storage capacity up to 725 GWh, which can be used to temporally shift the variable power from solar and wind. Similarly, gas power could be used to generate electricity for meeting the electrical demand when the low-carbon power is not sufficient.

Fig. 3 shows the optimised power flows in the three systems. Each of the power flows consist of 17,520 snapshots, namely a sequence of 30-min time window over a year. The electrical demand in 2018 is used for the three systems. The techno-economic performance results of the three systems are listed in Table 2.

With the added energy generation from solar and wind in system b, as shown in Fig. 3b, the system's dependence on fossil fuels is significantly reduced compared to system a (Fig. 3a). The demand met by fossil fuels decreases by 70% due to the direct use of the low-carbon energy if available. However, solar and wind alone is not always sufficient due to their non-dispatchable and weather-dependent nature. About 16% of the generation is curtailed when the low-carbon generation is higher than the demand. The low-carbon power is lower than the electrical demand about half of the time, requiring gas plants to provide complementary power for the system balance. Nevertheless, the availability of the increased low-carbon energy results in a 74% carbon emission reduction with only about 5% cost increase based on the mean levelised cost of utilised electricity of the power system (system LCOUE, see Appendix).

In system c with the optimally designed CAES plants (specifications of optimal results are listed in the Appendix) using the power flow optimisation, the utilisation rate of the low-carbon sources is improved such that the curtailment rate reduces from 16.3% in system b to 7.7% in system c. As shown in Fig. 3c, the CAES plants can shift the low-carbon power from the high-generation periods to the high-demand periods, further mitigating the power system dependence on fossil fuels. The use of CAES also reduces the maximum power capacity of fossil fuels to less than 20 GW from about 35 GW in system a and system b, significantly downsizing the required power capacity of gas plants. As a result, most of the low-carbon sources (92%) are utilised to achieve a further 38% carbon emission reduction compared to system b, which is 84% carbon emission reduction compared to system a. Compared to the 1990 level [52] which is the reference often used for determining the emission goals, system c has a 95% reduction of the emissions due to electricity generation.

This significant decarbonisation is achieved by shifting the low-carbon power over a wide range of timescales and cycling patterns. According to the optimal power flow results, the CAES plants using the salt caverns provide electricity for the system balance from hours to days. Most of these CAES plants (site 1–3 and 6–12) can provide more than 1-day discharging at the rated power, mainly operated at multi-day to bi-weekly cycling (29–91 cycles per year). As shown in Fig. 4, most cycle times of these potential CAES plants are more than 24 h, accounting for more than 60% of their storage cycles.

As shown in Fig. 4, in contrast, site 4, 5 and 13 have much more frequent cycling mainly for shorter duration storage, due to their low electrical storage capacity and relatively high cycle efficiency. The full-power discharging time of sites 4 and 5 is about 6 h, mostly providing daily cycling. In the obtained optimal power flow results, the cycle time that is less than 24 h accounts for 93% of the storage cycles undertaken by the site 4, 5, and 13, demonstrating their major role in daily storage.

4. Does a combination of solar, wind, and CAES have the potential to cost-effectively replace current gas power plants?

The decarbonisation achieved by system b from system a is solely due to the use of low-carbon solar and wind power to replace the fossil fuels. Although a non-perfect usage rate of these intermittent sources (16.3% curtailment rate) is assumed, the enhanced solar and wind

Table 2
A technical, economic, and environmental comparison between the three studied power systems.

Power system investigated	System a	System b	System c
Demand met by fossil fuels [%]	47.6%	14.4%	8.9%
Solar and wind in total generation [%]	17.89%	64.4%	64.4%
Curtailment of low-carbon generation [%]	0%	16.3%	7.7%
Carbon footprint of fossil-fuel power [Mton/year]	62.6	16.1	9.9
LCOUE of power system (mean) [$/MWh]	58–109 (84)	57–119 (88)	78–138 (108)

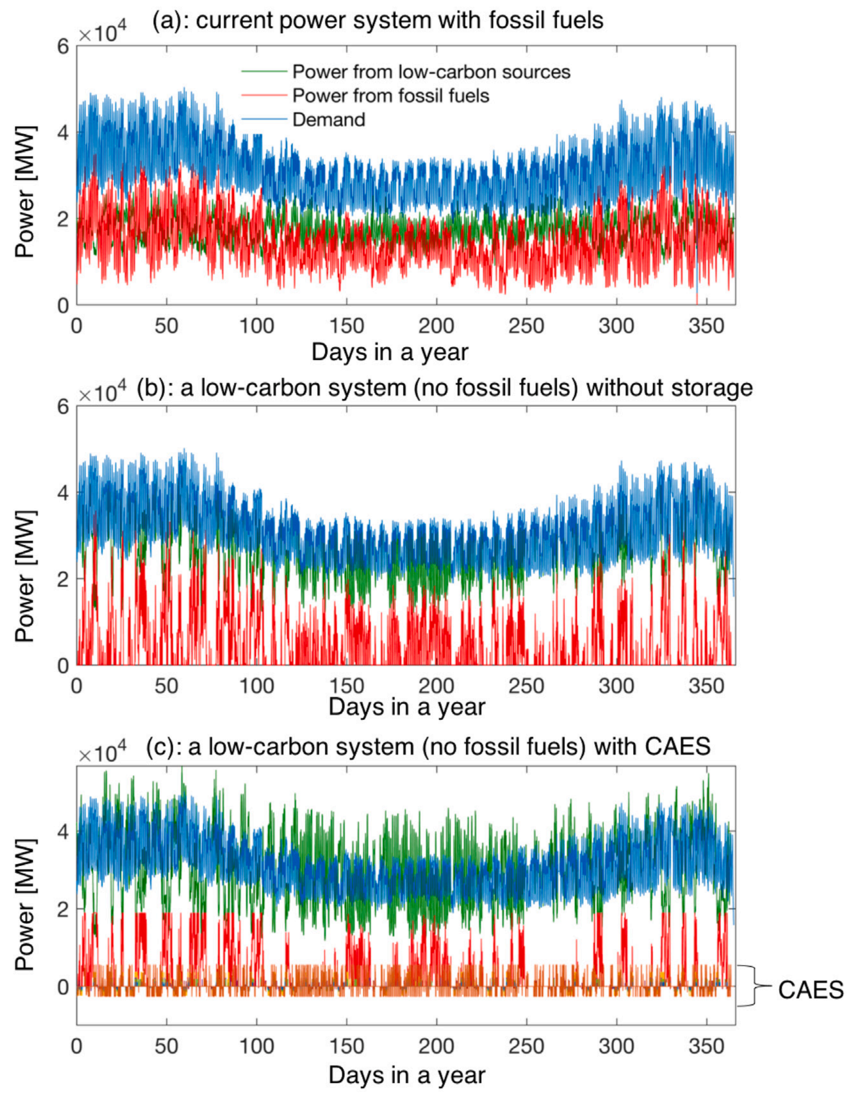

Fig. 3. Power flow of the three studied power systems. The results of the system a, system b, and system c are plotted in Figure (a), (b), and (c) respectively. The available low-carbon generation (not plotted) in the system b and system c is same, but the used generation (plotted) is different due to the capability of the system to use.

power can significantly mitigate the use of fossil fuels. It is a simple direct replacement of fossil fuels by low-carbon sources with gas power as back-up flexible generation. As the total energy generation from the added solar and wind in system b is the same as the original generation from fossil fuels in system a, the power system cost mainly relies on the utilisation rate (or curtailment rate) of the low-carbon sources and the differences of Levelised Cost of Electricity (LCOE) and carbon density between the low-carbon sources and fossil fuels. As the LCOE of solar and wind power is lower than the fossil fuels (including gas and coal), when the curtailment rate is low the added power system cost is low.

However, this decarbonisation cost increases rapidly when the power system is further decarbonised, as the curtailment rate increases substantially. Thus, towards a deep decarbonisation of the power system, the value of bulk-scale energy storage is to reduce the decarbonisation cost. Fig. 5 plots the mean system Levelised Cost of Utilised Electricity (LCOUE) of the decarbonisation, when system b and system c are further deeply decarbonised respectively. The system LCOUE increases rapidly when the decarbonisation rate is close to 100%. In the decarbonisation scenarios with various generation mixes from solar and wind (please find the detailed solar-wind mixes in Appendix), as shown in Fig. 5, at the decarbonisation rate 98.5%, the system LCOUE is roughly tripled using the simple fuel replacement which is same to system b by increasing the power capacity of solar and wind in generation but without storage, compared to the current power system (system a). In contrast, the use of CAES plants as bulk-scale energy storage can significantly reduce the decarbonisation cost. As shown in Fig. 5, the cost is much lower than the low-carbon system without

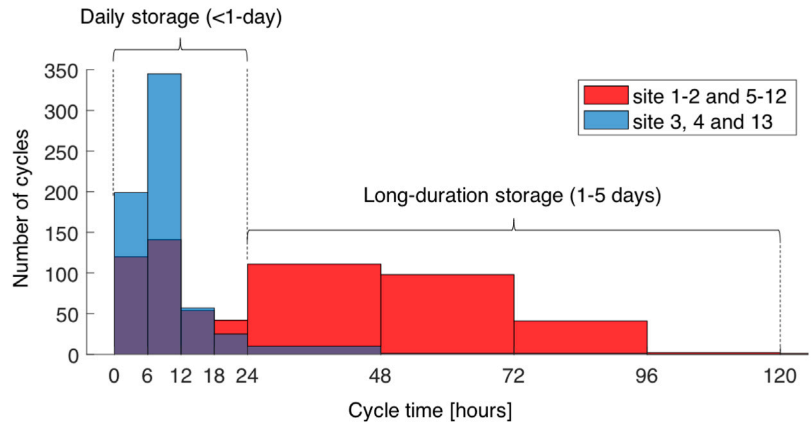

Fig. 4. Histogram of optimised cycle numbers of the potential CAES systems using current salt-cavern gas storage facilities.

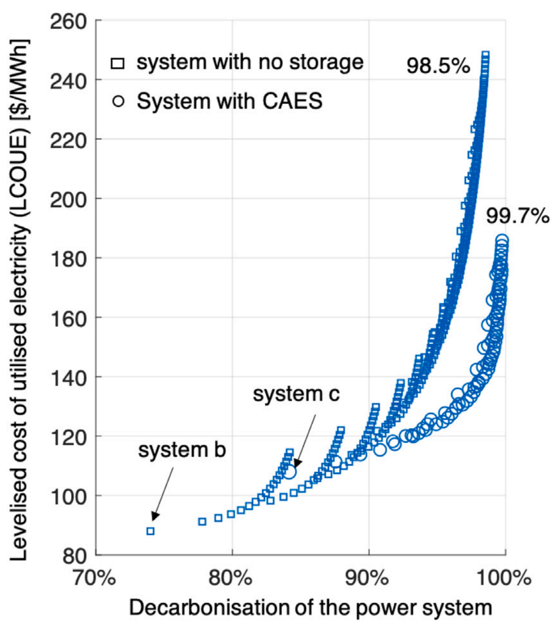

Fig. 5. Levelised cost of utilised electricity (mean) of the power system.

storage to achieve the same decarbonisation rate (i.e. 99.7%), given the high increasing rate of the system cost with no storage towards 100%.

Besides using the storage, two other factors can affect the power system cost. The first is the demand pattern, particularly the considered duration of the demand. Fig. 6a plots the LCOUE of the system with the average demands over 30-min, 6-hour and 1-day respectively. These analyses enable the assessment of the power system cost when CAES acts as a bulk-scale energy storage in the system balance with a longer duration (i.e. hours to days) on the grid, which prioritises electricity services with a larger timescale than an hour. These services potentially include large-scale renewable energy integration and seasonal storage [8,53]. Table 3 lists the LCOUEs of system c when it is used to meet the demands with the different time windows.

The system cost of system c decreases with the increase of the considered duration in the system balance. The mean LCOUE of system c decreases by 3% and 14% respectively, when the duration of system balance increases to 6-hour and 1-day, respectively. The cost reduction is primarily due to the decrease of the required CAES storage capacity caused by the electrical storage capacity reducing by 76% and 94% respectively. Furthermore, as shown in Fig. 6a, within the considered solar and wind scenarios, the low-carbon power system with the potential CAES sites can provide 100% of average electricity demand over 6-hour and 1-day during the whole year with reduced costs at about $128/MWh and $111/MWh (mean LCOUE) respectively. These costs are much lower than the power system cost for meeting every 30-min demand.

Secondly, the sharp cost increase towards a fossil-fuel free power system can be mitigated by increasing the electrical storage capacity. Fig. 6b plots the mean system LCOUE of the power systems in which fossil fuels are fully removed so that the system is 100% decarbonised and no back-up gas power is available. The lines with symbol refer to the scenarios of different solar and wind installations considered (see Appendix), and the symbol indicates the lowest mean LCOUE of each considered low-carbon power scenario. The results indicate: (1) the system LCOUE is lower than the costs shown in Fig. 5b, if more electrical storage is used. The lowest mean LCOUE is about $198/MWh to meet 100% of the 30-min electrical demand over a whole year when 2000 GWh CAES storage capacity is available. The cost is 136% higher than the cost of system a, but lower than the cost of system c with 725 GWh CAES storage. The capacity is about 2.8 times the estimated storage capacity of the current 13 gas storage facilities; and (2) the lowest cost of the power system occurs at the mix of 8 times wind power and 9 times solar power compared to the current power system. Although the absolute numbers of the LCOUE or the solar and wind power may need more precise analysis for guiding deployments in practice, this analysis indicates that an optimal mix of solar and wind with a sufficient CAES capacity could lead to a reasonably low-cost low-carbon power system.

5. Discussions

Although clearly a theoretical and simplified calculation of the power decarbonisation, using the geological resources at the scale of current underground gas storage facilities for CAES could provide significant bulk-scale storage capacity and flexibility currently provided by fossil fuels in the system balance on various timescales from half-hour to days with a plausibly affordable electricity cost. A partial use of these A-CAES plants that store air in the current gas storage facilities could significantly reduce the planning and construction time of the bulk-scale energy storage plants. The positive impacts of these systems, including reduced carbon emissions, increased energy utilisation efficiency, and reduced the cost of decarbonisation in the power sector, could increasingly become significant with the rapidly growing share of variable low-carbon generation on the grid.

Many power systems across the world (e.g. Europe, US, and China) are increasingly installing low-carbon generations such as solar and wind on the grid to reduce the carbon emissions in the power generation. The current installed capacity of combined solar and wind in the UK is about 38 GW, in which solar is about 14 GW and wind is about 24 GW [54]. The maximum power generation is lower than the

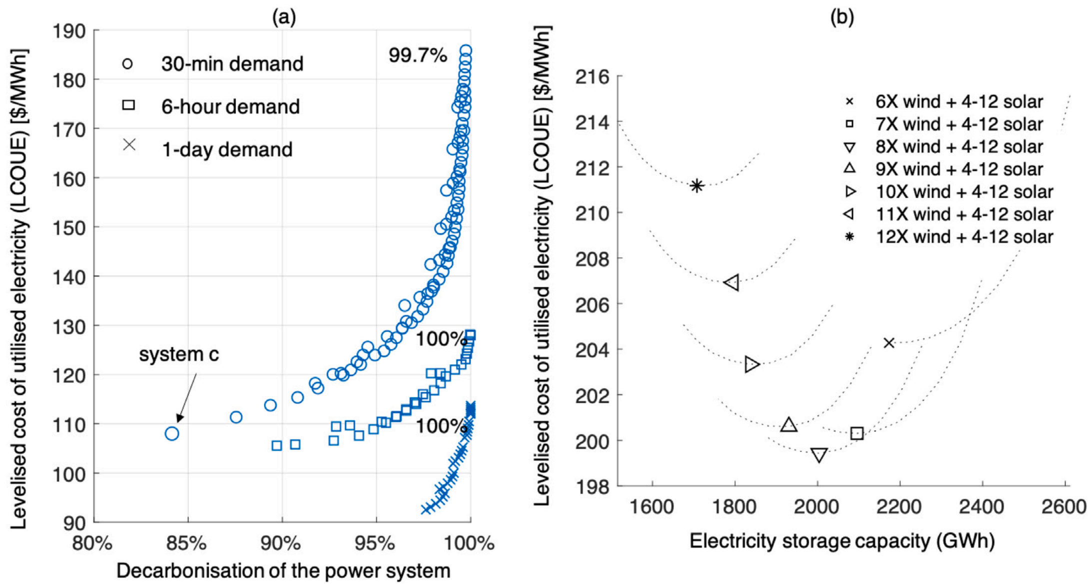

Fig. 6. The factors that affect the mean LCOUE of the power system. (a): the duration in the system balance. (b): the available storage capacity.

Table 3
The system c with three demand profiles over three time windows.

Time window of demand	30-min	6-hour	1-day
LCOUE of power system (mean) [$/MWh]	78–138 (108)	76–135 (105)	64–121 (93)
Required storage capacity [GWh]	725	174	40

peak of the 30-min demand (50 GW), but already higher than the mean 30-min electrical demand (31 GW). This is similar in Europe in which the combined solar and wind contributes to about 18% in the total power generation [3]. Therefore, a curtailment may occur anytime in the system when the combined solar and wind power generation is high. At present, similar to system b, the cost of reducing the carbon emissions is very marginal due to the low share of solar and wind in the generation, which is more than two times lower than the share in system b. A substantial amount of bulk-scale energy storage such as the CAES plants is not essential at this stage.

However, the more intermittent low-carbon power generation the power system has, the more techno-economic benefits these CAES plants would bring. As indicated by Fig. 5, the system cost rises sharply due to the low utilisation rate when the share of variable renewable power is high. Studies have indicated that the variable power generation from solar and wind will likely exceed the peak electrical demand in 2030 [55], and could even reach to 200%–300% of the peak electrical demand in 2050 [55–59]. Given an always temporal mismatching between these variable power supply and the electrical demand, building a capability of the power system to store large-scale electricity from solar and wind now is critical for ensuring a maximised utilisation of the newly-built renewable infrastructure in the next decade for reducing carbon emissions. In addition to the UK, this is true for the countries that have committed to decarbonise their power system using intermittent renewable energy sources.

The cost added to the power system due to the use of these CAES plants as bulk-scale energy storage was also estimated in this study. Based on the analysis that with a 29% power system cost increase, the combination of solar, wind, and CAES can reduce the carbon emissions of the power system to less than 10 MtonCO$_2$/year, 84% less than the emission in 2018 and 95% less than the 1990 level. If only balancing the supply–demand variations over 6-hour and 1-day, the costs of the power system are much lower. These results indicate a low-cost pathway to realising a deep decarbonisation in the UK, by using the salt-cavern based CAES plants as an underlying bulk-scale energy storage. This potential low-cost power decarbonisation pathway with the salt-cavern based CAES as the backbone storage may also apply for many countries in Europe, North and South America and Sub-Saharan Africa where favourable geological resources are abundant.

Although the cost of using CAES to decarbonise the power system is relatively low compared to other energy storage technologies, at present, the investment on a bulk-scale CAES plant often seems more risky financially. The root cause is the low revenue generated by the bulk-scale storage in the current electricity market and limited long-term policy and regulatory visibility for such bulk-scale energy storage [60]. Because these bulk-scale storage plants are CapEx-intensive, they need visible and stable revenue streams to demonstrate that they are able to pay back the initial investments or loans over a relatively long term. However, current electricity markets mainly incentivise the services for providing short-duration flexibility (seconds to minutes), such as frequency and reserve services, rather than the operation of long-duration (hours to days) services. Also, specifically in the UK, there is no long-term contract or policy for new bulk-scale storage technologies other than PHS at the moment, leaving CAES to an unfavourable position in the competition with batteries and gas power plants in the electrical markets on the timescales of seconds to minutes and half-hour to days, respectively. These factors end up adding uncertainties to the CAES project's lifetime economics and stepping down the confidence of investors, although the cost of CAES plants is actually low among all storage technologies. To use the available resources with the well-established CAES technology for meeting the demand on the timescale of hours to days, which could replace the role of current fossil-fuel generation, therefore, electricity markets need to be improved to promote the bulk-scale energy storage. Firstly, it is important to diversify the timescales of incentives on flexibility provisions on the timescales of hours to days from low-carbon sources. Secondly, the visibility and certainty of the long-term economics of bulk-scale storage needs to improve by establishing long-term (10+ years) contracts with system operators, similar to PHS plants and fossil-fuel generators. Also, a fair environment for different technologies could be built by recognising the desirable but currently non-rewarded benefits to stabilise the grid, including spinning inertia, reactive power, deferring infrastructure upgrade, and reducing carbon emissions.

Moreover, to have more precise cost estimations of the power system with these CAES plants, many other predictions of future energy scenarios and costs should be included to optimise the electrical storage capacity and optimal power flows. The real demand data of the UK power system in 2018 was used as the starting point to estimate the cost of power decarbonisation with CAES. Future electrical demand may be increased by 50% due to the electrification of heating and transport [61], so both required low-carbon generation capacity and electrical storage capacity needs to be increased as well. In addition, the cost analysis in this study was based on a simple cost analysis using the LCOEs of various power sources, assuming the LCOEs remain same among different generation mixes. The LCOEs of solar and wind will likely further drop after a massive deployment, and the LCOEs of fossil fuels will potentially increase due to the reduced use over their lifetime and tightening regulations on carbon emissions. Either of them will positively affect the power system cost in the decarbonisation.

The analysis was based exclusively on CAES as storage to integrate the large-scale solar and wind for decarbonising the power system considering a time window no less than 30-min. The power decarbonisation could be improved with other approaches mainly including: (1) other electrical storage technologies that are primarily for short-duration (seconds-hours) storage such as lithium-ion batteries; (2) other long-duration (hours to days and beyond, i.e. weeks to months and seasons to years) energy storage techniques such as hydrogen energy storage and flow batteries; (3) demand side management that directly manipulates the demand; (4) carbon capture and sequestration with fossil-fuel power plants that reduce the emissions of fossil fuels; and (5) other low-carbon power sources such as biomass and hydro as a generation replacement of fossil fuels. All of these approaches can mitigate the difficulty in the system balance by adding more low-carbon dispatchable generation sources (4 and 5), more storage over a wide range of timescales (1 and 2), or flexibility on the demand side to improve the alignment between generation and demand (3). With these improvements, the requirement for CAES in the decarbonisation would be further mitigated. For example, CAES plants with one or more gas storage facilities could be used primarily for the prolonged durations, e.g. 6-hour and 1-day, at a low cost. Also, these decarbonisation approaches could also provide other essential short-duration (seconds to minutes) electricity services, which is not the focus of this study.

For the power dispatching, it is very challenging and uncertain to predict the temporal patterns of a future decarbonised system. It was assumed that the added solar and wind power is proportionally increased based on the current solar and wind power pattern, which allowed the investigation of how to shift the intermittent low-carbon sources and optimise the power system cost at a similar scale. Although a theoretical study and not a realistic cost for planning, the estimated costs can quantitatively compare and analyse different scenarios considering the temporally variable power generation and electrical demand. Importantly, the proposed framework and method is applicable to optimise the power capacities and dispatching patterns of CAES plants using other power inputs with different temporal patterns. Studies incorporating an optimal spatial planning of solar and wind power with the consideration of the power transmission capacities could further guide the installation of solar and wind for achieving the deep decarbonisation.

6. Conclusions

In the coming decades, with the increasingly installed solar and wind power, a reliable and affordable decarbonised power system based on variable energy sources may depend on the ability to store large quantities of low-cost energy over multiple timescales. Compressed Air Energy Storage (CAES) is a promising technology for many countries across the globe that have abundant geological resources suitable for salt-cavern based bulk-scale storage. Using the UK power system as a case study, this study presents a framework for assessing national-scale geological resources favourable for CAES, optimise and planning CAES system design and operation on the scale of over 100 GWh, and discusses policies and market design to promote low-cost bulk-scale energy storage in power system decarbonisation from now towards 2050.

Although further analysis may be needed to improve the understanding of the precise electricity cost in the decarbonisation with CAES, solar and wind, this analysis provides two key findings: (1) the amount of electrical capacity of CAES using underground caverns from the salt-deposit resources on a similar scale to the existing underground gas storage facilities can substantially boost the country's capacity for bulk-scale energy storage by at least an order of magnitude. On a national basis, the potential resources for new salt-caverns as further underground gas storage is also ample, providing substantial flexibility to further scale-up the storage capacity of CAES and coordinate the resources with other technologies. (2) The bulk-scale CAES plants combined with solar and wind can substantially reduce the carbon emissions of the power system with relatively low cost by significantly reducing the system dependence on fossil fuels. The cost further decreases when CAES plants are used for balancing the average variations between supply and demand over a longer duration, when CAES acts as a storage on the timescales of hours to days. If more CAES storage capacity was available, the power system cost for the decarbonisation without fossil fuels could be even lower.

To ensure a smooth transition to the net-zero system in the mid of this century, a well-planned energy system upgrade with a long-term perspective is essential. As pointed out in this study, a substantial amount of bulk-scale energy storage may not be necessary for current power systems despite a significant fraction of power is deprived from solar and wind. However, the costs of low-carbon electricity will increase rapidly when the power system is further decarbonised, requiring low-carbon sources to provide the flexibility currently offered by fossil fuels. In many regions, CAES has the potential to play an important role as bulk-scale energy storage to large quantities of low-cost energy over multiple timescales, ensuring a maximised utilisation of the renewable infrastructure to be built in the next decade during the power system decarbonisation.

CRediT authorship contribution statement

Wei He: Conceptualisation, Methodology, Data curation, Investigation, Software, Writing - original draft, Writing - review and editing, Visualisation, Funding acquisition. **Mark Dooner:** Conceptualisation, Methodology, Writing - review and editing. **Marcus King:** Conceptualisation, Methodology, Writing - review and editing. **Dacheng Li:** Writing - review and editing. **Songshan Guo:** Data curation. **Jihong Wang:** Supervision, Funding acquisition, Writing - review and editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Table 4
Cost parameters of CAES used in the power flow optimisation.

Variable	Value
LCOE of CCGT, [$/MWh]	41–74 [63]
LCOE of OCGT, [$/MWh]	152–206 [63]
LCOE of solar PV, [$/MWh]	36–44 [63]
LCOE of wind, [$/MWh]	29–92 [63]
LCOE of nuclear, [$/MWh]	112–189 [63]
LCOE of biomass, [$/MWh]	50–150 [64]
LCOE of coal, [$/MWh]	60–143 [63]
LCOE of hydro, [$/MWh]	20–60 [64]
Carbon intensity of CCGT, [$kgCO_2$/MWh]	405 [17]
Carbon intensity of OCGT, [$kgCO_2$/MWh]	710 [17]
Carbon intensity of coal, [$kgCO_2$/MWh]	1025 [17]
Interest rate, [%]	8
lifetime of the power system, [year]	40

Appendix. Method and supplementary information

A.1. Electrical energy capacity

Exergy analysis can be used to estimate the electrical storage capacity of a cavern with a defined storage volume [62]. Most CAES plants use uncompensated underground salt-mined caverns as air storage, such as the Huntorf and McIntosh plants. Uncompensated underground salt-mined caverns can be regarded as constant-volume air storage in which pressure is varying during both charging and discharging processes. If the caverns are assumed to be isothermal air storage vessels, the maximum exergy storage, namely the theoretical maximum electrical capacity, can be estimated using:

$$B = B_T + B_p = \left\{ \frac{pV}{RT}[c_p(T - T_0) - T_0 c_p ln(\frac{T}{T_0})] + \frac{pVT_0}{T}[ln(\frac{p}{p_0}) - 1] \right\}_{p_{initial}}^{p_{final}} \tag{1}$$

where B_T and B_p represents the exergy capacity contributed by the enhanced temperature and pressure respectively. p, V, and T are the pressure, volume, and temperature of air respectively. R is the ideal gas constant. The subscript 0 denotes the environmental condition. The subscripts $initial$ and $final$ refers to the initial and final conditions in the charging or discharging processes.

In practice, air temperature variations in caverns significantly affect the exergy storage [62]. Factors such as air flow rate, surface area of caverns, and heat transfer rates with the surroundings can change the air mass and exergy stored in the same caverns as much as about 40% [62]. To address these factors, mathematical models of the thermodynamic responses of air in a cavern were developed subject to cavern operation in isochoric uncompensated or isobaric compensated modes, and heat transfer conditions including isothermal, convective heat transfer and adiabatic wall conditions [62]. Details of the derivation and other factors that affect the electrical energy capacity can be found in [62].

The electrical storage capacity estimated in this study is based on the theoretical maximum, so the analysis with these estimated capacities could indicate a maximum potential of salt-cavern based CAES in the UK with a storage capacity at a similar scale to the current gas storage facilities. This preliminary analysis could be a starting point to further analyse and plan for CAES plants in the UK. It should be noted that if the realistic electrical storage capacity is considered, the volume for air storage in new caverns will be larger. This additional volume can be met by the identified geological resources (e.g. Fig. 1b).

A.2. The adiabatic CAES configuration

Fig. 7 illustrates the considered A-CAES system configuration, which was investigated in [53]. The system is composed of: (i) motor and generator units that engage with compressors and expanders respectively; (ii) multi-stage air compression operating with a group of Heat Exchanger (HEX) to extract the compression heat; (iii) multi-stage air expansion with another group of HEXs to heat the compressed air in the expansion stage; (iv) HEXs that exchange heat between hot air from compressors, thermal reservoirs, and cold air to expanders; (v) "hot" and "cold" water-based thermal storage reservoirs working with the two groups of HEXs to form the Thermal Energy Storage (TES) cycle; and (vi) underground caverns for storing compressed air.

As shown in Fig. 7, CAES has four main components: compressor, expander/turbine, storage (thermal and air), and motor/generator. During charging process, the motor that is powered by electricity drives the compressors to pressurise air. After compression a HEX reduces the hot air's temperature to a regulated value, and the heated water is stored in the thermal reservoir. After being pressurised by compressors and flowing through HEXs, the cooled compressed air is pumped into an underground cavern. The charging stops when the cavern pressure reaches its maximum value. When electricity is needed from the CAES system, the compressed air is reheated by flowing through the HEXs for exchange of heat in thermal energy storage. Finally the heated pressurised air expands in the expander, which drives a generator to produce electrical power output. In order to avoid evaporation, water is pressurised to 4 bar (i.e. ~0.4 MPa) so that the evaporation temperature increases to about 140 °C.

Using water as the working fluid for thermal energy storage, the main advantages include: (1) water is an inexpensive and readily available medium for heat storage; (2) water-based HEXs are widely available in the market; and (3) water is environmental friendly for heat storage. However, the temperature of hot water is limited by its boiling temperature (e.g. 100 °C at about 0.1 MPa), which may decrease the quality of thermal energy stored for CAES discharging.

The A-CAES system architecture has been demonstrated in the field by several research projects in which one is the 1 MW ALACAES project in Switzerland [33] and another one is the 10 MW Bijie CAES project in China [34]. The experimentally demonstrated cycle efficiency are 60.2% and 72% respectively. Currently, the same R&D team and manufacturer in China are building a 100 MW A-CAES project in Jingbian, Shaanxi, aiming to achieve a cycle efficiency over 70% [65].

A.3. Thermodynamic modelling of the adiabatic CAES

The A-CAES model used for analysing the system cycle efficiency is from [66]. Using the model, the CAES is modelled as an isentropic compression for pressurising air, isobaric cooling for reheating air, isobaric heating for extracting the compression heat, and isentropic expansion to drive generators for power generation. Detailed assumptions and explanations of the model can be found in [66].

The air compression in the charging process can be approximated by an isentropic compression process, which is,

$$W_{i,c} = \frac{1}{\eta_c \eta_m} \frac{\gamma}{\gamma - 1} RT_{i,1}[(\frac{p_{i,2}}{p_{i,1}})^{\frac{\gamma-1}{\gamma}} - 1] \tag{2}$$

where $W_{i,c}$ refers to the power consumption of the compressor at stage i. η_c and η_m are the efficiency of the compressor and motor respectively, which are assumed to be 87.5% and 98% respectively [66]. γ is the isentropic index, which is 1.37. $T_{i,1}$ and $p_{i,1}$ are the air temperature and pressure at the inlet of the ith stage compressor, respectively. $p_{i,2}$ is the pressure at the outlet the ith stage compressor.

Similarly, the work generated by the jth expander can be approximated by,

$$W_{j,e} = \eta_e \eta_g \frac{\gamma}{\gamma - 1} RT_{j,1}[1 - (\frac{p_{j,2}}{p_{j,1}})^{\frac{\gamma-1}{\gamma}}] \tag{3}$$

where $W_{j,e}$ refers to the power generation of the expander at stage j. η_e and η_g are the efficiency of the expander and generator respectively, which are assumed to be 92.5% and 98% respectively [66]. $T_{j,1}$ and

Table 5
The optimised charging and discharging power capacities of the potential CAES plants using underground gas storage facilities.

Site No.	Site name	Charging capacity [MW]	Discharging capacity [MW]
1	Horsea	811	1220
2	Aldbrough I	1008	1385
3	Whitehill	1608	1888
4	Holford H165	29	53
5	Hilltop Farm/Hole	870	1522
6	Holford	398	455
7	Stublach	607	864
8	King street energy	205	308
9	Keuper has storage	1005	1130
10	Gateway	3122	3666
11	Preesall	800	886
12	Islandmagee	1437	2211
13	Portland	3235	5594
Total		15,135	21,182

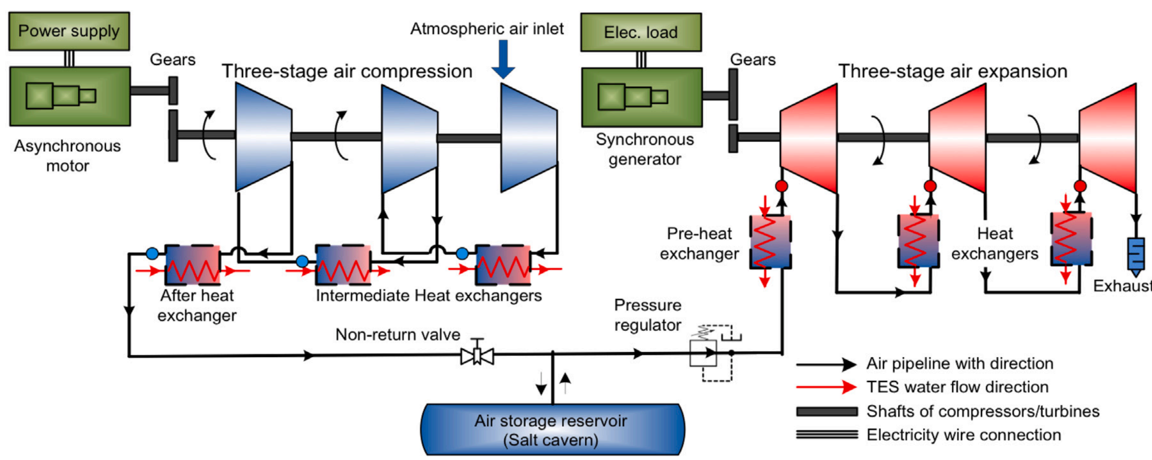

Fig. 7. The considered A-CAES architecture in the study.

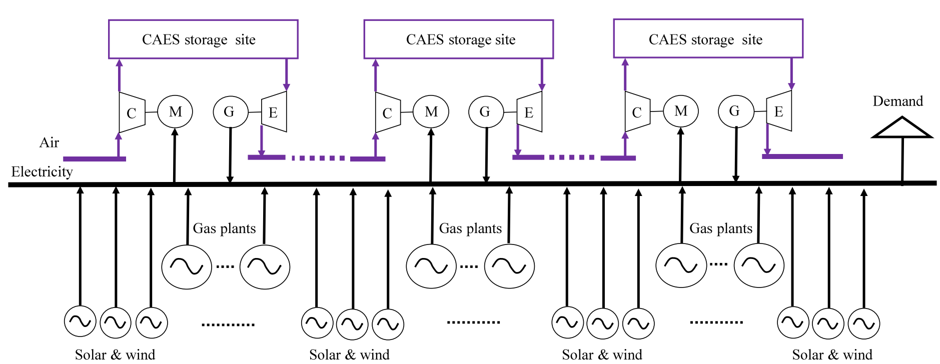

Fig. 8. An illustrated diagram of the power flow model built in PyPSA.

$p_{j,1}$ are the air temperature and pressure at the inlet of the jth stage expander, respectively. $p_{j,2}$ is the pressure at the outlet of the jth stage expander.

The pressure ratio and expansion ratio per stage is assumed to be around 3. Depending on the total pressure ratio of the compression and expansion, a constant pressure ratio per stage is calculated. It was also assumed 98% of the stored heat in the pressurised hot water can be used to reheat the air in the discharging process. The assumed constant heat loss is a simplification of the realistic cases, which is based on short-term thermal energy storage. It should be noted that the longer duration to store the heat the higher heat losses may occur. As a result, the higher heat losses may affect the temperature of the reheated air, negatively affecting the electrical cycle efficiency, which is

$$\eta_{cycle} = \frac{\sum_{j=1}^{N_j} W_{j,e}}{\sum_{i=1}^{N_i} W_{i,c}} \tag{4}$$

where η_{cycle} is the overall cycle efficiency of the CAES system. N_i and N_j are the stage number of air compression and expansion respectively.

Our analysis indicates that if the thermal storage efficiency reduces to 50% in all the sites (e.g. for seasonal storage), the cycle efficiency is 43%–54%, which is about 23% less on average, compared to the values plotted in Fig. 2b. These negative effects of low cycle efficiencies on the economics of CAES might be insignificant if the cycle number is low. Additional volume for air storage in CAES could compensate the reduced electrical cycle efficiency, as the energy storage cost in $/kWh is low. The effect of the heat losses in thermal energy storage will be considered in future studies.

A.4. Power flow modelling and optimisation

Power flow optimisation represents the problem of optimising the temporal operating levels for electric generators and storage in order to meet demands given throughout a transmission network, usually with a predefined objective. PyPSA (“Python for Power System Analysis") is used in this study [67] for simulating and optimising the low-carbon power systems that include gas generators with unit commitment, variable wind and solar generation, CAES units, and a simplified network. The PyPSA tool allows one to [67]: (1) simulate static power flow; (2) minimise total power system least-cost investment with predefined available solar and wind power supplies over yearly snapshots. The cost minimisation was achieved using linear network equations by optimising the power ratings and dispatching of the potential CAES plants and gas power plants. The objective is to minimise the total system cost, including the variable and fixed costs of generation, storage and transmission, given technical and physical constraints.

The focus of this study is to explore the use of the potential CAES plants to minimise the use of current gas power in the power system. As a result, in the power flow optimisation, the capital costs of gas, solar and wind power are not considered; only the operational costs are considered, as these generators have been built. The operational cost of solar and wind power is also assumed to be negligible, due to their nature of CapEx-intensive technologies. Thus, the objective function considered in this study is given by

$$min\left[\sum_{n} c^{p}_{CAES}H_n + \sum_{n} c^{E}_{CAES}E_n + \sum_{n,t} w_t o_{CAES}[h_{n,t}]^{+} + \sum_{t}(w_t o_{gas} g_{gas,t})\right] \quad (5)$$

where H_n and E_n are the storage power capacity and energy capacity respectively at each CAES plant n. c^{p}_{CAES} and c^{E}_{CAES} are the annualised fixed cost per power capacity and energy capacity respectively. o_{CAES} is the variable cost during operation of the storage. $[h_{n,t}]^{+}$ is the power dispatching during storage charging process. $g_{gas,t}$ is the temporal dispatching of the unit at time t. o_{gas} is the associated operating cost of gas power. To prioritise the use of CAES over the gas power in the system, the operating cost of gas power is set with a weight w_t. This objective is also used in the power flow optimisation. As a result, gas power would be used only when the potential of CAES with solar and wind is not enough to meet the demands. When the storage capacities, power capacities, and the dispatching patterns of CAES and gas are optimised, the system cost is estimated using Eq. (6) rather than Eq. (5). In the power flow optimisation, the annualised fixed cost per power capacity and energy capacity of CAES are \$871/MW and \$39/MWh respectively [8]. The variable cost during operating the storage, which is also the electricity price for charging is \$50/MWh [8].

The maximum solar and wind power generation is predefined, which is a set of scenarios with assumed increasing rates. The energy capacity of each CAES plant is predefined according to the maximal electricity capacity estimated using Eq. (1) and the site-based geological conditions listed in 1. The model built using PyPSA is illustrated in Fig. 8. Cbc solver is chosen to solve the optimisation problem [68]. Details of the tool can be found in [67,69].

A.5. Cost and carbon emission modelling

To assess the overall cost and CO_2 emissions of the entire power system that includes various power sources (e.g. gas power, solar, wind, nuclear, and biomass) and potential CAES plants, cost and emission models are used. Similar to LCOE (levelised cost of electricity), LCOUE (levelised cost of utilised electricity) is developed, which is

$$\text{LCOUE} = \frac{\text{lifetime cost of the power system}, C_{sys}}{\text{lifetime electrical demand met of the power system}, E_{sys}} \quad (6)$$

in which

$$C_{sys} = \sum_{l}(\text{LCOE}_l \times \text{lifetime generation of the power } l) = \sum_{l}(\text{LCOE}_l \sum_{j=1}^{j=N}\frac{E^{y}_{g,l}}{(1+r)^j}) \quad (7)$$

$$E_{sys} = \sum_{j=1}^{j=N}\frac{E^{y}_{d,l}}{(1+r)^j} \quad (8)$$

where l denotes the energy sources such as solar, wind, gas, biomass, and nuclear. $E^{y}_{g,l}$ refers to the one-year electrical generation from the power source l. E^{y}_{d} refers to the one-year electrical demand of the power system. r is the interest rate. j is the year number during the lifetime N years.

Similarly, the total annual carbon emissions due to the fossil-fuel based can be estimated by,

$$M_{CO_2,sys} = \sum_{l}\dot{M}_{CO_2,l} \times E^{y}_{g,l} \quad (9)$$

where $\dot{M}_{CO2,l}$ is the carbon intensity of fossil fuels. Table 4 lists the parameters used for cost and carbon emissions modelling.

A.6. The optimised results of the CAES plants

The specifications of the optimised CAES system designs are listed in Table 5. These optimised charging and discharging power capacities determine the size of compressors and turbines for the potential 13 CAES sites.

The discharging time at rated power and the cycle number of the 13 CAES sites in the optimal power system are plotted in Fig. 9. Most of the CAES plants can offer discharging more than one day (site 1–3 and 6–12), indicating the potential for large-scale energy storage. In addition, these CAES plants (site 1–3 and 6–12) have less frequent

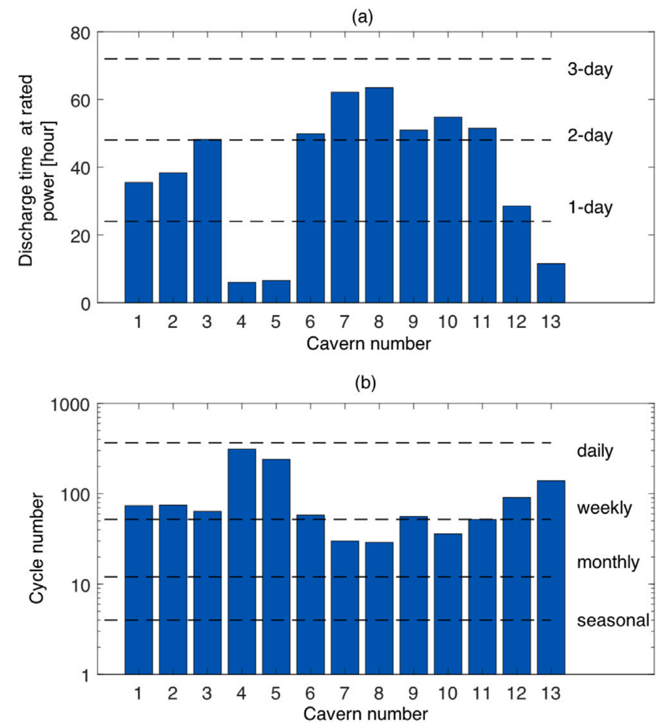

Fig. 9. Performance of the optimised CAES plants. Discharging time at rated power in (a) and the cycle number in (b).

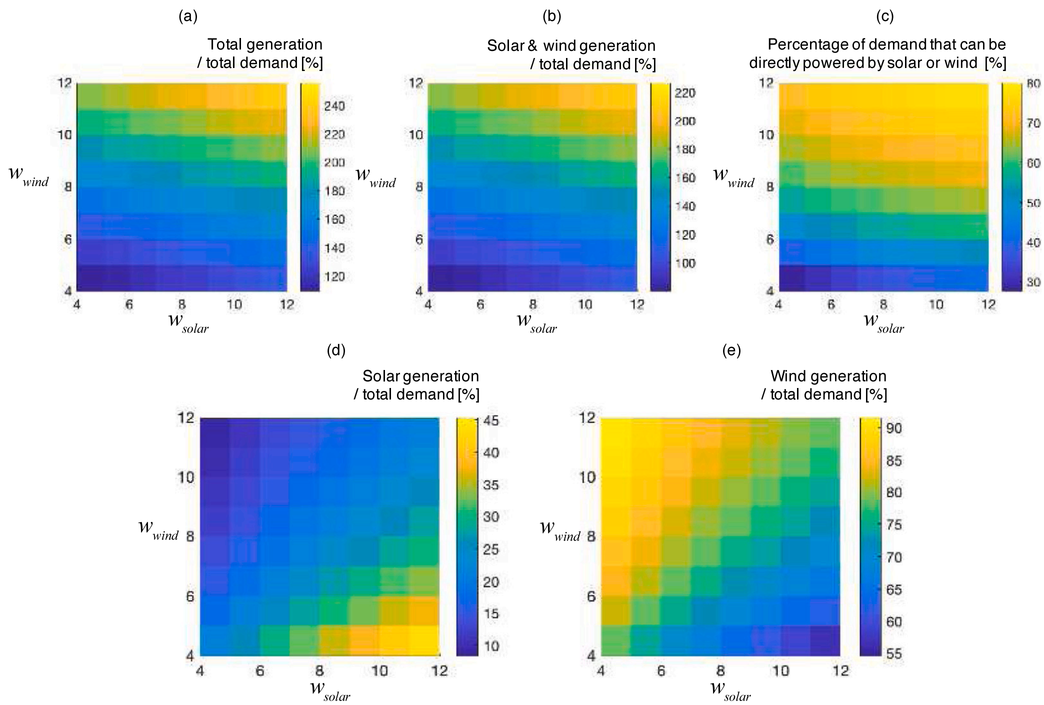

Fig. 10. Details of the considered scenarios. (a) plots the fraction of the total generation to the demand in 2018. (b) plots the fraction of the total solar and wind generation to the demand in 2018. (c) plots the fraction of the demand that can be directly met by the solar and wind generation. (d) plots the fraction of the solar generation to the demand in 2018. (e) plots the fraction of the wind generation to the demand in 2018.

operation which cycle from half-week to bi-week, indicating the use for long-duration. In contrast, the other CAES plants which have less discharging time at rated power also cycle more frequently. On average, site 4 and 5 almost cycle every day, and site 13 cycles every 1–2 day.

A.7. Scenarios of solar and wind power for the decarbonisation

In system b and system c, it was assumed that the low-carbon power system has added 131 TWh from solar and wind power (which is same to the total annual generation from fossil fuels in 2018). This added solar and wind generation is about 2.6 times the current annual generation of solar and wind in 2018. The solar and wind power is assumed to be added by proportionally increasing the power by 2.6 times at each time snapshot over a whole year. In addition to the original solar and wind power, the total solar and wind generation in system b and system c is 3.6 times the generation from solar and wind in 2018. Same to this scenario generation mechanism, further scenarios with deeper decarbonisation are generated by increasing the solar and wind power independently with the generation factors, w_{solar} and w_{wind}, from 4 to 12, respectively. The generation in these scenarios is,

$$P_{gen} = w_{solar}P_{solar} + w_{wind}P_{wind} + P_{other} \quad (10)$$

where P_{gen} is the total generation time-series, P_{solar} is the solar power time-series in 2018, P_{wind} is the wind power time-series in 2018, and P_{other} is other low-carbon generation time-series in 2018, including nuclear, hydro, and biomass.

Fig. 10 shows the details of the scenarios generated with the considered generation factors. In the considered scenarios, the total generation to the demand considered is up to about 250% of the demand in which the solar and wind generation can be as high as about 220% of the demand. However, only up to 80% of the demand can be met by the solar and wind power directly due to the intermittence. In particular, as the solar annual generation is only one fourth of the wind annual generation in 2018, based on the used scenario generation method, the fraction of wind generation in the total generation is much higher than solar. In the most solar-dominant scenario, as shown in Fig. 10d, the solar can contribute to about 45% of the demand. In contrast, in the most wind-dominant scenario, as shown in Fig. 10e, the wind can contribute to more than 90% of the demand.

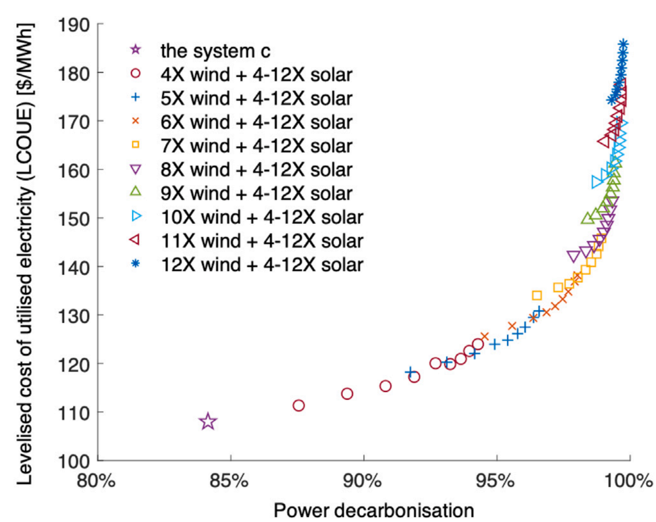

Fig. 11. The mean system LCOUE in scenarios with various mixes of solar and wind generation.

Fig. 11 plots the mean system LCOUE of all the considered scenarios with the 13 potential CAES sites, as well as system c, which differentiates the different scenarios with symbols. It shows the (mean) system LCOUE becomes increasingly high when the power decarbonisation progresses towards the zero-carbon system. As wind contributes much more to the total generation, the increase of the wind generation factor w_{wind} drives the trend faster than solar. In the considered scenarios, the highest power decarbonisation rate is 99.7% with a mean system LCOUE of about $190.

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