

Application of Liquid-Air and Pumped-Thermal Electricity Storage Systems in Low-Carbon Electricity Systems

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Abstract

In this study, we consider two medium- to large-scale electricity storage systems currently under development, namely ‘Liquid-Air Energy Storage’ (LAES) and ‘Pumped-Thermal Electricity Storage’ (PTES). Consistent thermodynamic models and costing methodologies for the two systems are presented, with the objective of integrating the characteristics of these technologies into a whole-electricity system assessment model, and assessing their system-level value in different scenarios for power system decarbonisation. It is found that the value of storage varies greatly depending on the cumulative installed capacity of storage in the electrical system, with the storage technologies providing greater marginal benefits at low penetrations. Two carbon target scenarios showed similar results, with a limited effect of the carbon target on the system value of storage (although it is noted that this may change for even more ambitious carbon targets). On the other hand, the location and installed capacity of storage plants is found to have a significant impact on the system value and acceptable cost of these technologies. The whole-system value of PTES was found to be slightly higher than that of LAES, driven by a higher storage duration and efficiency, however, due to the higher power capital cost of PTES, this becomes less attractive for implementation at lower volumes than LAES.

Keywords: liquid-air energy storage, pumped-thermal electricity storage, power system economics, whole-system assessment.

Introduction

The competitiveness of any energy storage technology is strongly affected by its technical and economic characteristics. A storage system that is both efficient and economically competitive has the potential to support a flexible and efficient low-carbon electricity system. It can support cost-efficient integration of intermittent renewable generation and take advantage of differences between peak and off-peak electricity prices as well as provide local and national services to network and system operators. The application potential of any technology in a power system will depend on its characteristics in combination with the requirements of the whole system.

Electricity storage systems can provide flexibility required for cost-effective integration of variable renewables into future power systems [1]. Energy storage technologies have different characteristics, such as power capacity, energy capacity, charge and discharge durations, and can therefore have different purposes in the electricity grid. Although it is important to determine and analyse both their technical and economic properties, it is also vital to assess their realistic value in an electricity system. This assessment can be challenging for newly proposed technologies with limited data, but on the other hand it can provide a first indication of the attractiveness of such technologies at a system level. This paper focuses on the potential deployment of two newly proposed technologies, namely Liquid-Air Energy Storage (LAES) and Pumped Thermal Electricity Storage (PTES), in low-carbon electricity systems.

Methodology

A whole-system assessment approach is adopted here in order to determine the whole-system value of contribution of energy storage in low-carbon electricity systems. A full description of the modelling approach is included in Ref. [2]. The whole-system model, WeSIM, determines optimal decisions for investing into generation, network and/or storage capacity, in order to

satisfy the real-time supply-demand balance in a least-cost sense, while at the same time ensuring security of supply. An application of WeSIM was presented in Ref. [3] that quantified the value of energy storage in supporting cost-efficient decarbonisation of the electricity system i.e. delivering the carbon reductions at lower total cost. A similar approach was used in Ref. [4] to assess the role and value of pumped hydro electricity storage in the European power system.

Electricity storage technologies

LAES is a technology being developed by Highview Power Storage [5]. The LAES system involves four main processes: a) air liquefaction, b) liquid air storage, c) waste cold storage, and d) power generation; see simplified schematic in Figure 1a. During charging, the system uses inexpensive electricity to liquefy air and gets charged by storing energy in the form of liquid air, and during peak demand periods, when it becomes economically attractive to discharge, the system uses liquid air in the power generation unit where this is pressurised, evaporated, superheated to the temperature of the utilised waste-heat stream (if available) and expanded through a turbine to generate electricity [6]. Although optional, an additional process which was found to be a contributing factor for the enhancement of the system's performance is the storage of waste cold from the power generation unit during the discharging periods and the utilisation of that cold in the air liquefaction process during the charging periods. More details on the workings of a LAES system are given in Refs. [6-10].

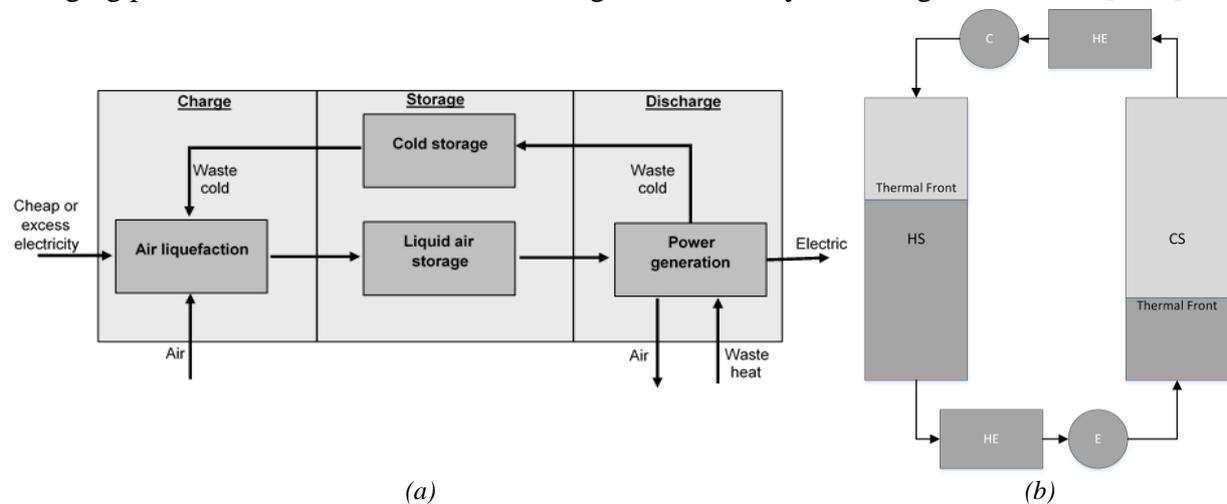


Figure 1. Schematics of: (a) LAES system (adapted from Ref. [9]) and (b) PTES system (adapted from Ref. [11])

PTES is also a newly proposed electricity storage system, but at a lower Technology Readiness Level (TRL) than LAES due to the lack of an operational pilot plant (although one is currently under construction). PTES stores energy in the form of sensible heat in insulated storage tanks containing a storage medium [11]. It operates based on a reverse/forward Joule-Brayton cycle for charging/discharging, respectively [11,12]. The system consists of two thermal reservoirs at different temperatures and pressures when charged, two reversible expansion/compression devices [13,14] and two heat exchangers (see Figure 1b). In the charging mode heat is extracted from the cold reservoir and pumped into the hot reservoir, thus resulting in increased temperature difference. During discharging, the flow of the working fluid is reversed to take advantage of the temperature difference, and a heat engine is used to generate electricity.

The thermodynamic (first law) performance of energy storage systems is typically expressed in terms of a roundtrip efficiency (η), defined as the net work output (W_{out}) during discharge divided by the net work input (W_{in}) during charge (Eq. 1):

$$\eta = \frac{W_{out}}{W_{in}} \quad (1)$$

Here, W_{out} and W_{in} for the two systems can be estimated using the charge and discharge thermodynamic cycles associated with each system. For LAES, W_{out} is the power generated during the discharge cycle, whereas W_{in} is the work input into the liquefaction unit during the

charge cycle (see Figure 1a). Several operational and loss parameters can have an impact on the estimation of η of LAES, for example the amount of waste cold and heat utilization as well as the components' efficiencies. For PTES, W_{out} and W_{in} are estimated by considering forward and reverse Joule-Brayton cycles for discharging and charging, respectively. Similar to LAES, the performance is also significantly affected by a number of operational and component performance variables. The main losses to be considered in such a system include pressure losses, compression and expansion losses, and thermal losses in reservoirs [11-16].

Both LAES and PTES are relatively new technologies and consequently information on their costs is limited in the available literature. Therefore, and in order to obtain consistent estimates of the capital costs of both systems, a costing methodology was developed based on simple thermo-economic models and a costing exercise was performed [7,8]. The overriding aim of this exercise was to perform a preliminary economic feasibility assessment of the two technologies that would allow their assessment from a whole-system perspective.

In the costing model used specifically for the estimation of capital expenditure, the systems were broken down into their fundamental components for costing and then summed to obtain an estimation of the overall system costs. Where possible, installation costs were considered. The model uses various methods for costing the different components. In summary, for expanders/turbines, compressors, pumps and storage vessels the costing correlations based on [17] are used along with their associated factors and parameters to estimate the capital cost. For heat exchangers, the model obtains an approximation of capital costs based on the C-value method [18] which allows for simple costing without the necessity of calculating the heat exchanger area requirement. For the storage material in the storage vessels a specific cost of £100/t is used in the model while assuming magnetite as storage material [15,16]. Finally, for the cost estimation of generators, the model uses a capacity exponent factor approach given that alternative correlations such as the ones presented in Ref. [17] were not found in literature. This approach is based on the following relation in which the exponent factor (e) used is 0.94 [19]:

$$C = 1.85 \cdot 10^6 \left(\frac{\dot{W}}{1.18 \cdot 10^4} \right)^e \quad (2)$$

where C is the capital cost in € and \dot{W} is the power output capacity of the generator in kW.

Whole-systems assessment model

Analysing future electricity systems at sufficient temporal and spatial granularity is essential for adequately assessing the cost-effectiveness of decarbonisation pathways and enabling technologies. In order to accurately quantify system operation and investment cost as well as its carbon performance, quantitative models need to simultaneously consider second-by-second supply-demand balancing issues as well as multi-year investment decisions. Furthermore, it is also critical to adequately consider the synergies and conflicts between local and national (or trans-national) level infrastructure requirements.

To that end, the Whole-electricity System Investment Model (WeSIM) described in Ref. [2] is used in this paper to determine the value energy storage technologies in supporting efficient investment and operation of future electricity systems. The model minimises total system cost, which consists of: a) investment cost of new generation and storage capacity and the reinforcement cost of transmission and distribution networks, and b) operating cost of generators in the system, taking into account the cost of fuel and carbon. A detailed model formulation is included in Ref. [2]. Key features and constraints include: a) power balance, b) reserve and response, c) generator operating limits, d) demand-side response; e) distribution network investment, f) carbon emissions, and g) security constraints.

Assessing the value of energy storage in future electricity systems

A *gross value* approach is adopted in this paper to assess the benefits of energy storage. In the first step, this approach consists of minimising the total system cost for an appropriately constructed *counterfactual* scenario, in which there is no energy storage. In the second step, a

series of model runs is carried out with gradually increasing energy storage capacity, and the resulting reduction in total system cost is interpreted as whole-system benefit of energy storage. Scenarios with energy storage do not assume any cost of storage, hence providing gross (rather than net) system benefits. Gross system benefit can be a useful benchmark to compare against the projected cost of a given energy storage technology.

In this paper the gross whole-system value of storage is quantified in two ways:

1. *Average* whole-system value, obtained by establishing the cost reduction between a given energy storage scenario and the corresponding counterfactual scenario, and then dividing cost savings with the total assumed capacity of energy storage (in kW or kWh). For instance, if the scenario with 10 GW of energy storage results in total system cost savings of £1bn per year, the average gross system value or energy storage is £100/kW per year.
2. *Marginal* whole-system value, obtained by establishing the cost reduction between a given energy storage scenario and the previous scenario with lower storage capacity, and then dividing it with the incremental capacity of energy storage. For example, if in the scenario with 10 GW of energy storage the total system cost savings are £1bn per year, and the one with 5 GW of energy storage resulted in £0.6bn of annual cost savings, the marginal gross system value or energy storage is £0.4bn divided by 5 GW, or £80/kW per year.

Marginal value of storage is particularly suitable for comparison with estimated costs of storage technologies. It decreases with the installed capacity of storage, as the benefits of first MWs added will be higher than those of subsequently added storage capacity due to diminishing returns and reduced cost savings opportunities. Marginal value provides an indication of the cost-efficient level of deployment, given the basic economic principle that energy storage should be deployed up to the level where its gross marginal value equals its cost.

Description of scenarios used in the analysis

Scenarios used to assess the system value of energy storage technologies in this paper are constructed to capture the key drivers for the value of flexibility provided by energy storage. In all scenarios the power system is designed and operated to meet one of the two levels of *carbon emission intensity*: 100 g/kWh or 50 g/kWh. These carbon targets broadly correspond to the targets for the UK power system in the 2030-2040 horizon.

All scenarios are constructed by optimising the portfolio of generation technologies to meet the carbon target, while meeting electricity demand with adequate level of security of supply. Technologies available for adding to the system included: wind, solar PV, nuclear and CCS, as well as conventional generation technologies such as CCGT and peaking gas generation (OCGT). In order to represent typical variations in renewable output and demand across different geographies, the scenarios were developed to represent either *North* or *South* of Europe, with utilisation factors in the North higher for wind and lower for PV than in the South, and peak demand occurring during winter in the North and during summer in the South.

The electricity system is assumed to be represented by a single node. System demand has been sized to broadly correspond to the GB system demand at 347 TWh annually, of which 8.4% and 7.8% was associated with electrified transport and heat demand, respectively. The central assumption in all scenarios was that the uptake of demand-side response (DSR) was 25% of its theoretical potential, allowing a proportion of demand to be shifted in time. DSR in the model is provided by flexible electric vehicles, heat pumps, residential appliances and industrial and commercial demand. Sensitivity studies were also carried out for DSR uptake levels of 0% and 50% to study the competition between DSR and energy storage.

The counterfactual scenarios were assumed not to contain any energy storage. The capacity of each of the two energy storage technologies studied in this paper, LAES and PTES, was varied between 0 and 25 GW in 5 GW increments. The respective assumed durations (ratios between energy and power) for LAES and PTES were 4 hours and 5.75 hours, while the assumed cycle efficiencies were 55% and 70%. It was assumed that both technologies were connected to the high-voltage electricity distribution grid.

The costs of generation technologies were assumed based on the authors' own projections. The levelised cost of electricity (LCOE) for wind was taken to be £40.85/MWh in the North of Europe and £48.27/MWh in the South, and for solar PV it was taken to be £68.72/MWh in the North and £42.00/MWh in the South. The LCOEs of nuclear and CCS (assuming 90% annual load factor) were £133.67/MWh and £93.38/MWh, respectively. Investment costs for CCGT and OCGT generators were assumed at £687/kW and £568/kW, respectively. The assumed cost of gas was £22.62/kWh, while the carbon price was £29.09/t.

Results and Discussion

Electricity storage technologies costs

In the case studies considered in this paper, the LAES and PTES systems were analysed within their expected operating parameters: for LAES, a power output capacity of 12 MW and energy capacity of 50 MWh were used, and for PTES a power output capacity of 2 MW and energy capacity of 11.5 MWh were used. Thermodynamic and costing models of LAES and PTES were used to estimate their power capital cost (total capital expenditure divided by the power capacity), and energy capital cost (total capital expenditure divided by the energy capacity).

The estimated power capital cost of PTES and LAES was found to be around £2,700/kW and £1,600/kW, respectively. The equivalent values in terms of the energy capital costs for PTES and LAES were estimated at about £500/kWh and £400/kWh, respectively. It is recognized that at different capacities and power to energy ratios the power and/or capital costs might change and this represents an area for future work. For the cases considered here, these cost estimations indicate a slight competitive advantage of LAES in terms of both power and energy capital cost. However, the capital cost estimates do not reflect the system value of each technology in a given electricity system. Therefore, a combination of both cost and value estimates is adopted to assess the attractiveness of these systems in low-carbon electricity systems.

System value of energy storage technologies

Generation portfolios in counterfactual scenarios (without any energy storage) are shown in Figure 2 for North and South of Europe scenarios and 100 and 50 g/kWh carbon targets. In the North the carbon target is achieved mostly by installing around 80 GW of wind generation, and CCS capacity (more so at 50 g/kWh). The remainder of the portfolio consists of CCGT and OCGT generation to ensure sufficient capacity margin. South scenarios contain a mix of wind and PV capacity, as well as CCS capacity that is higher than in comparable North scenarios.

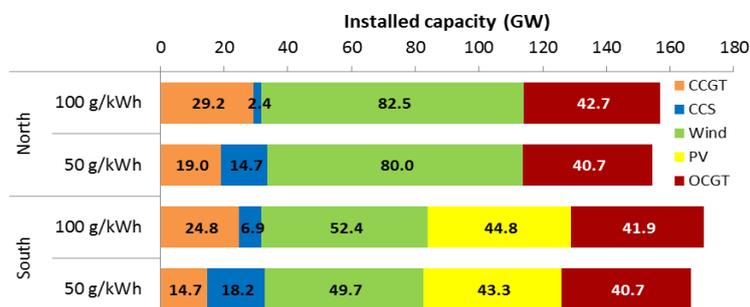


Figure 2. Generation technology mix in counterfactual scenarios (without energy storage)

System values of LAES and PTES were then quantified as described earlier. Given that the system optimisation provided annual cost savings, these annualised values were converted to capitalised values assuming the same system value would be generated over the lifetime of the storage asset, assuming the lifetime of 20 years and cost of capital of 7%. Figure 3 shows the average and marginal values of the two energy storage technologies expressed in £/kW across a range of scenarios and uptake levels.

Several key observations can be made: a) system value of storage decreases with higher uptake levels, as expected, and marginal value decreases faster than the average value; b) the value of PTES is in most cases higher than for LAES due to the positive effect of higher duration and

higher efficiency; c) system value is considerably higher in the South than in the North, driven by higher variability of PV generation compared to wind; and d) values in 50 g/kWh scenarios are consistently higher than for 100 g/kWh, although not significantly. The value of storage was found to vary across scenarios between about £800/kW and £2,500/kW. Note that had these values been expressed in £/kWh, i.e. divided by the durations of the two technologies, the value of PTES would reduce relatively to LAES due to the higher assumed duration.

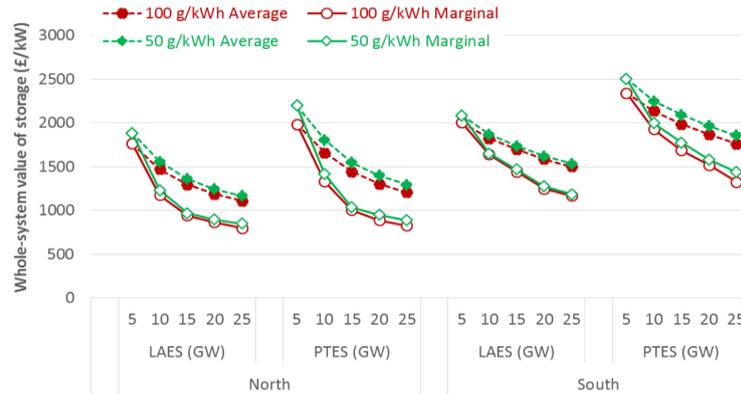


Figure 3. Average and marginal system value of LAES and PTES technologies

The whole-system modelling approach allows for specifying the breakdown of marginal values of LAES and PTES into components: investment cost (CAPEX) and operating cost (OPEX) of low-carbon generation, CAPEX and OPEX of conventional generation and CAPEX of distribution networks. This is illustrated in Figure 4 for 50 g/kWh scenarios.

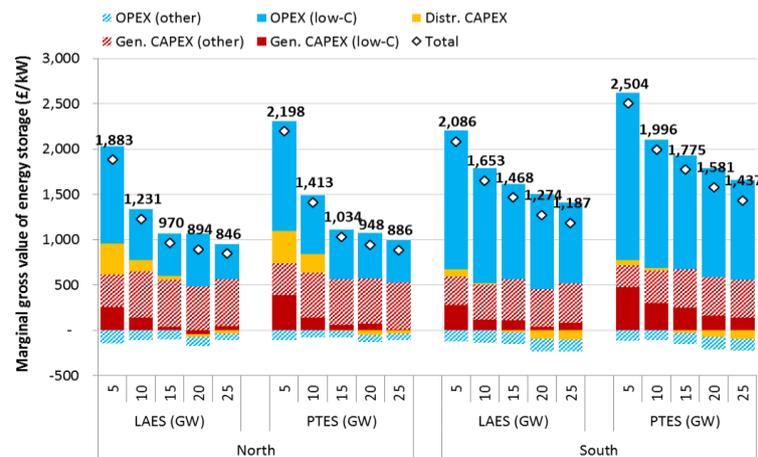


Figure 4. Breakdown of marginal system value of LAES and PTES technologies (50 g/kWh)

Key components of system value of energy storage can be identified as: a) avoided CAPEX and OPEX of low-carbon generation (largely CCS), resulting from higher operational efficiency and lower renewable curtailment; b) avoided CAPEX of conventional generation, given that storage can displace conventional generation in contributing to the capacity margin; and c) for lower levels of storage penetration in the North there is avoided distribution CAPEX driven by energy storage reducing peaks in the distribution grid. In most cases deploying energy storage results in a slight increase in the OPEX of conventional generation given that a part of CCS generation is replaced by less expensive but more carbon-intensive CCGT output.

It is clear that the value of storage can materialise in different segments of the electricity system. In reality this would mean that to maximise its economic value an energy storage operator would need to simultaneously deliver multiple services to the system [3].

Finally, to quantify the impact of competing flexible providers on the whole-system value of energy storage, two sets of sensitivity studies were run where the uptake level of DSR was set either at a low (0%) or high (50%) level. The effect on the marginal system value of LAES

and PTES is shown in Figure 5. As expected, a higher DSR uptake would result in a lower value of storage and vice versa. This occurs because the cost saving opportunities that are accessible to storage are also accessible to DSR, hence there is direct competition between the two flexible options. The effect of higher DSR uptake is moderate, with the average reduction in value across all scenarios around 10%. On the other hand, a low DSR uptake would increase the system value of energy storage by 25% on average.

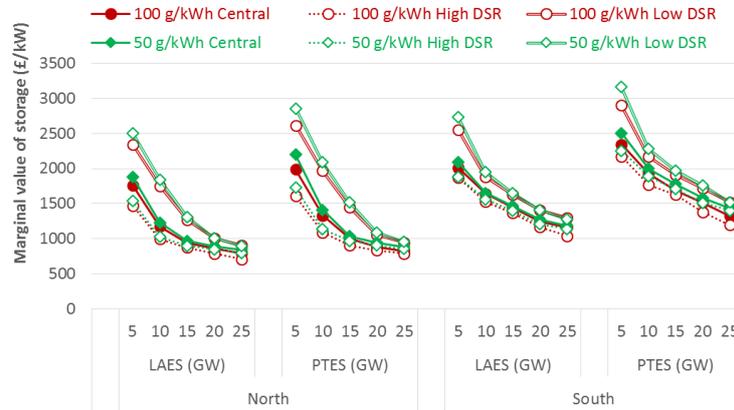


Figure 5. Impact of DSR uptake on marginal system value of LAES and PTES technologies

Conclusions

Consistent thermodynamic and economic models were developed and applied to determine the characteristics of LAES and PTES systems. Differences in key system characteristics in earlier work [7,8] indicated these should be tested in a network-scale model to identify the conditions in which each technology is more valuable. Therefore, their application in a whole-system model was investigated to determine the system value of storage under different scenarios.

The whole-system value of electricity storage was found to greatly vary depending on the cumulative installed capacity of storage in the system. Considering that the marginal system value of storage can be considered equivalent to the maximum acceptable cost of the storage system at a given penetration, we can use the cost estimates of LAES and PTES to say if the systems are attractive for implementation under different system scenarios, and at what level of installed capacity. Storage technologies provide greater marginal benefits at low penetrations and can therefore be viable in these conditions at a higher capital cost.

The two carbon target scenarios showed similar results, with limited effect of carbon target on the system value of storage (although this may change for even more ambitious carbon targets). On the other hand, the location and installed capacity were found to have a greater impact on the system value and acceptable cost of the technologies. Whole-system value of PTES was observed to be slightly higher than for LAES, driven by higher duration and efficiency; however, due to the higher power capital cost of PTES, it becomes unattractive for implementation at lower volumes than LAES. The cost of PTES was found to be higher than its whole-system value at the minimum capacity considered, except in cases with low DSR uptake. LAES, on the other hand, is found to be attractive for implementation at installed capacities between 5 and 10 GW in the North of Europe and between 10 and 15 GW in the South. The cost-efficient volume of LAES increases even further in scenarios with low DSR uptake.

Future research in this area will include exploring other costing methods/correlations for these technologies that might result in lower costs. Also, if learning curves are considered as a result of incremental installed capacity which can contribute to the reduction in cost estimates, it is possible that the systems will be economically attractive at even higher installed capacities. Also, investigating LAES and PTES at different capacities and power to energy ratios can be an interesting avenue for future work. Finally, it will be of interest to investigate in more detail the competition between LAES, PTES and other energy storage technologies if they are all simultaneously considered in the system.

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