A TECHNO-ECONOMIC REVIEW OF POTENTIAL INTER-SEASONAL ENERGY STORAGE IN A FULLY GREEN POWER GRID

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Keywords: TECHNO-ECONOMIC, INTER-SEASONAL ENERGY STORAGE, ELECTRICITY GRID

Abstract

The shift to a net-zero world drives a push for electrification across sectors. Energy storage is important for integrating renewable systems to enable a stable, flexible and affordable power supply. Li-ion batteries are effective for short-term (daily, weekly) balancing due to their falling production costs, fast response, and high round trip efficiency. However, they are less suitable for long-term storage (monthly and seasonally) due to their short storage duration.

This paper reviews cost structures and technical features of six technologies that could manage inter-seasonal power supply balance. It examines four potential storage options - compressed air energy storage, vanadium and zinc flow battery and power to X (green hydrogen). As well as two technologies designed for seasoning use, bioenergy + CCS (BECCS) and natural gas + CCS.

This research compiles the identified key economic and technical data from 23 academic between 2018 and 2023. It reports the variability of economic data, such as marginal costs, CAPEX, and OPEX. It also reports variability of technical data, including round-trip efficiency, capacity factor, and lifespan of the selected storage technologies. Using such data, it estimates the levelized cost of electricity (LCOE) of the selected energy storage options as a proxy to reflect the changes in the number of yearly cycles (charge-discharge) or yearly production days (for extra winter capacity). The study also presents a cost ranking for integrate into a fully decarbonised grid, with an in-depth discussion of their functionality based on the techno-economic conditions of several representative countries.

Preliminary results suggest that BECCS and natural gas + CCS are likely more expensive than other energy storage options and operate at a lower capacity factor, making them less suitable for managing seasonal demands. However, these findings are subject to uncertainties, such as future technology costs, evolving inter-seasonal energy storage policies, and potential investments. The results also indicate that CAES could be an economical inter-seasonal storage solution in a fully decarbonised grid, with an estimated LCOE ranging between \$0.08 and \$0.14 per kWh. Although hydrogen has not been a favourable economic solution for managing the inter-seasonal power demand-supply balance due to its higher LCOE (\$0.36–\$0.76 per kWh) compared to CAES, it has the potential to scale up quickly and has the capability to ensure the inter-seasonal, and even yearly, power demand-supply balance. Furthermore, the study indicates the need to develop future energy storage policies, focusing on investment strategies, the role of long-term storage in the electricity market, and revenue calculation mechanisms.

1 Introduction

The broader adaptation of electrification is likely the most cost-effective and practical solution to decarbonise the power, transport, heat and industry sectors in a net-zero world. The extensive deployment of solar and wind energy enables a smooth transition to electrification. However, using renewable systems to generate electricity is intermittent as the generation is subjected to meteorological conditions. Li-ion batteries can incorporate renewable systems to balance power demand-supply in the short term (e.g., hourly, daily) [1]. Long-term (e.g., monthly or seasonal) peak power demand-supply management is neither economically nor technically viable using Li-ion batteries. Meeting such demand might require an excessive number of Li-ion batteries, which may remain unused at other times.

Alternatively, the long-term power demand-supply balance is mostly managed by fossil fuels. Many countries, including China, the U.S., the U.K., and the EU, still rely on fossil fuels (e.g., coal, natural gas) to manage the seasonal peak power demand-supply balance. Fossil fuels, however, will be fully opt out in a net-zero world. Therefore, it is important to explore the alternative solutions, where an economically and technically optimal inter-seasonal storage can be a competitive solution to replace fossil fuels in managing the seasonal power supply-demand balance. According to the definition given by [2]inter-seasonal storage technologies feature a long continuous discharge duration and can be used to manage the peak demand-supply balance. Therefore, incorporating such inter-seasonal energy storage technologies can complement Li-ion batteries in managing the inter-seasonal power demand-supply balance in a highly renewable integrated electricity grid, leading to an affordable and secure decarbonised power supply grid.

[3]concluded the following types of energy storage can potentially to be used for inter-seasonal power supply-demand management purposes.

- Mechanical Storage (e.g., novel gravity storage, CAES, liquid air energy storage).
- Chemical (P2X).
- Electro-Chemical (e.g., flow batteries).
- Thermal (e.g., Latent heat storage, sensible heat storage, thermo-chemical sorption storage

Some existing studies (in Table 1) also explored the role of inter-seasonal storage to play in a fully decarbonised electricity grid.

Based on the findings in Table 1, existing studies have yet to investigate all potential energy storage technologies that can be used for inter-seasonal demand-supply power balance. Furthermore, only a limited number of studies have estimated, discussed, and compared the levelised cost of electricity (LCOE) for these potential inter-seasonal storage technologies. The LCOE is an important economic indicator for measuring and comparing the economic performance of different technologies effectively. Additionally, the estimation of LCOE is subject to uncertainty regarding future electricity costs, storage methods, installed capacity, and capacity factors. The relationship between these uncertainties and the estimated LCOE of potential inter-seasonal energy storage technologies has not been systematically examined in existing studies.

It then needs to further explore whether inter-seasonal energy storage is an economically competitive solution against other alternatives to replace fossil fuels in managing the seasonal demand-supply power balance. It is also unclear what the price range of using potential seasonal storage in delivering electricity is. Thus, we conduct a robust review of the inter-seasonal energy storage options from grey and white literature to address the abovementioned knowledge gaps. We first use the identified keywords to compile the inter-seasonal energy storage-related studies on the Web of Science, ScienceDirect and the top 200 articles on Google Scholar. We find five technologies that have the potential to be used to manage inter-seasonal demand-supply balance:

- compressed air energy storage (CAES),
- flow batteries (vanadium and zinc),
- power to hydrogen,
- bioenergy + CCS (BECCS) and,
- natural gas (methane) + CCS.

We then present a wide variety of CAPEX, OPEX, RTE (round trip efficiency), and lifespan data for the shortlisted five technologies based on the review findings. Afterwards, we introduce an LCOE model to estimate the range of LCOE (Levelized Cost of Electricity) for using these potential inter-seasonal energy storage technologies to manage seasonal demand-supply balances. The findings from the relevant studies and policies, combined with the estimated LCOE, can effectively support policymakers in strengthening future long-duration energy storage policies and leveraging the role of inter-seasonal storage in achieving a fully decarbonised grid.

2. Methodology

This section introduces two methods used in this research. Section 2.1 explains the method used to select the relevant inter-seasonal storage studies using the pre-identified keywords from three different academic study databases. The findings of these selected studies are used to demonstrate the range of economic and technical data for the shortlisted inter-seasonal storage technologies. Section 2.2 introduces the developed Levelized Cost of Electricity (LCOE) model used to calculate the range of LCOE for the shortlisted inter-seasonal energy storage technologies. The review findings, based on the method explained in Section 2.1, are used to input data into the LCOE model.

2.1 Literature review method

This research uses keywords including 'inter-seasonal energy storage,' 'techno-economic', and 'electricity grid' to compile the relevant research articles on the Web of Science, ScienceDirect and Google Scholar. This research only considers the top 200 articles in Google Scholar, as those articles are most relevant to the used keywords. It then identified 22 independent relevant research articles and eight inter-seasonal energy storage-related policy documents in G7 countries. The compiled independent studies are used to shape the understanding of the range of economic and technical performance of potential seasonal storage technologies. Whereas the policy documents are used to provide supplementary information like some cost or technical issues and policy implications that are not discussed in the independent studies.

The compiled research articles were published between 2018 and 2023 and included studies from ten countries on four continents (Asia, Africa, Europe, and North America). The results show that more inter-seasonal relevant studies were published from 2021 onwards (17 in total) compared to previous years (5 in total). The finding reflects that more inter-seasonal studies were conducted, along with the extensive integration of renewable systems in the electricity grid and the increasing number of installed heat pumps from 2021 onwards. Within those selected research articles, we also find that most compiled studies were published in the Journal of Energy Storage (4), followed by Applied Energy (3), Renewable and Sustainable Energy Reviews (2), Joule (2) and Energy Conversion and Management (2).

Five potential inter-seasonal energy storage technologies were discussed in the compiled research articles. The selected technologies can be categorised into two types: 1) energy storage technologies: compressed air energy storage (CAES) and flow batteries. 2) low carbon dispatchable technologies: bioenergy + CCS (carbon capture system), power to hydrogen to power, and natural gas (methane) + CCS.

2.1 LCOE estimation method

This subsection assumes that the needed capacity of inter-seasonal energy storage technologies is about 10 GW, and the capacity factor of running those technologies for seasonal usage is between 10-40%. The assumptions are derived from the existing studies published by[3]and[4] Such studies considered the actual cases in the UK that at least 31 TWh of generated electricity by renewable systems can be shifted across seasons. In addition, those studies found the operation hours of such CCGT+CCS (fuelled by natural gas) is between 10-40% on a yearly basis (capacity factor between 10-40%) to manage the seasonal power supply-demand balance in the representative EU countries and UK. Therefore, it assumes that at least 10GW of the selected potential seasonal storage technologies are needed to absorb 31TWh of excess electricity under the required capacity factor. The seasonal energy storage capacity is likely to increase in the future with the expansion of renewable systems.

In the LCOE calculation of P2X (hydrogen), this research did not calculate the levelized cost of hydrogen (LCOH) due to the highly uncertain of how the electricity is generated to power electrolysers, and the electricity price is significant discrepancies from the low-carbon grid, dedicated renewable systems or the curtailed electricity. This research then uses the projected future hydrogen production cost from the compiled hydrogen policies from the European Union, the U.K. and the U.S. to simplify the calculation, ranging from $1 to 3.6/kg ($0.03 – 0.11/kWh, while using LHV = 33.3kWh/kg H2) of hydrogen by 2030 and 2050. The lower bound of green hydrogen production cost is derived from the report published by IRENA in 2020 [5]. In the optimistic scenario, the green hydrogen production cost is expected to reach or even less than $1/kg in certain regions [6], [7]. The higher bound of the cost is derived from the UK's hydrogen production cost published by BEIS in 2021 [8]. In this cost calculation, BEIS adopted conservative assumptions (e.g., the technical performance of electrolysers has not improved significantly) to project future green hydrogen production costs. The average efficiency of 48% is used to calculate the LCOE of using hydrogen fuel cells to generate electricity.

In the LCOE calculation of using CAES as a seasonal energy storage option, it sources representative global electricity prices from the IEA report [9]. The compiled electricity prices are aligned with the agreed net-zero target, and they have been categorised into low, medium, and high on three scales. Different electricity prices from the future decarbonised grid ($45/MWh (min), $60/MWh (average) and $100/MWh (max)) are used to reflect a broad LCOE range of CAES. Those electricity prices are derived from the Electricity 2024 report published by [9], and such prices can represent the future global electricity price. Those projected electricity prices are also used to calculate the LCOE of flow batteries. However, in the LCOE calculation of flow batteries,

For the LCOE estimation of CCGT+CCS (fuelled by natural gas), this research uses the projected natural gas price predominantly based on the UK case; the data was estimated and published by the Department for Net-Zero and Energy Security (DESNZ) in 2023 [10]. DESNZ estimated low, central and high natural gas between 2022 and 2100 ($11.24/MWh, $31.23/MWh and $67.5/MWh). This research uses the compiled low, central and high prices between 2022 and 2100 as inputs to calculate the LCOE of CCGT+CCS. It also assumes that electricity from the grid is used to power CCS, and the CCS size is the same as that of CCGT. Therefore, the cost of the energy consumed by the system CCGT+CCS includes the electricity consumed for running CCS and the natural gas consumed by CCGT.

The calculation method of LCOE for the selected different inter-seasonal energy storage is explained in equations 1 to 6. The annual electricity (E_ele) supplied by the selected storage technologies is calculated using equation 1.

$$E_{ele} = C_{ins} \times CF \times 8760 \tag{1}$$

Where, C_{ins} is the defined capacity of 10GW, CF is the capacity factor assumed between 10-40%, and 8760 is the total hours in a calendar year.

The fuel (natural gas) or electricity consumed ($Con_{fuel/ele}$) for the estimated annual electricity supplied by the selected storage technologies is calculated using Equation 2.

$$Con_{fuel/ele} = {E_{ele}}/{RTE} \tag{2}$$

Equation 3 is used to calculate the associated storage cost for storing hydrogen or air in the salt cavern.

$$C_{salt\ cavern} = Con_{fuel/ele} \times C_{unit\ charge} \tag{3}$$

Where, $C_{salt\ cavern}$ is the total cost of storing the required hydrogen or air in the salt cavern. $C_{unit\ charge}$ is the unit charge of storing every kWh of air or hydrogen in the salt cavern.

Equation (4) is used to calculate the total cost of the consumed fuel ($C_{fuel/ele}$) based on the total amount of fuel or electricity consumed, as calculated in Equation 2.

$$C_{fuel/ele} = Con_{fuel/ele} \times C_{unit\ energy} \tag{4}$$

Where, $C_{unit\ energy}$ is the unit price of every kWh of the consumed electricity, natural gas or hydrogen.

The total cost of each storage technology is then calculated using Equation (5), with the specified average lifespan of each technology considered.

$$C_{total} = \sum_{n=1}^{lifespan} f(C_{\frac{fuel}{ele}}, C_{salt\ cavern}, C_{CAPEX}, C_{OPEX}) \tag{5}$$

Where, C_{CAPEX} is the CAPEX of the storage technology ($/kW) and C_{OPEX} is the fixed annual operational cost of the storage technology ($/kW*year). The fixed annual operational cost includes the annual maintenance cost, service cost, and labour charge but excludes the cost of the consumed fuel and electricity.

Then, the LCOE for each storage technology is calculated through equation (6).

$$LCOE = \frac{C_{total}}{E_{ele}} \tag{6}$$

This research applies a discount rate of 3.5% when calculating the total cost (C_{total}) and total electricity generation (E_{ele}). The discount rate is used to reflect the cost differences in annual costs and generation over the expected lifespan of each storage technology.

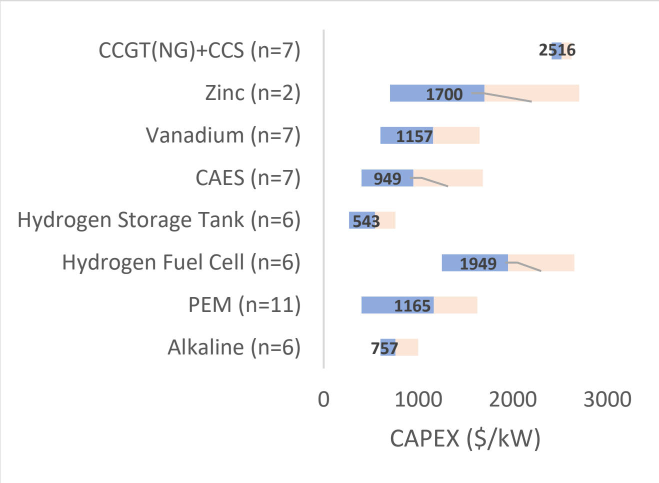
3. Results

Table 2 summarises the key techno-economic information from the selected relevant studies between 2018 and 2023.

3.1 Literature review results - Economic indicators

This subsection presents the key economic indicators, capital expenditure (CAPEX), and operational expenditure (OPEX) of the selected technologies from the compiled studies. The CAPEX in this research includes the total installation cost of the technology; the OPEX includes the standard annual service and maintenance cost. The associated fuel, water and energy costs are not included in OPEX. Several gathered studies provide the cost for electrolysers, hydrogen tanks and hydrogen fuel cell. Those separate costs can explain the reasons for the variations in hydrogen production costs.

The compiled studies use hydrogen in the hydrogen fuel cell, as the only by-product in this progress is water. Given that hydrogen can either be burned in hydrogen furnace or fed into hydrogen fuel cell to generate electricity. Burning hydrogen in hydrogen furnace can cause the development of NOx. Therefore, using hydrogen in the hydrogen fuel cell is one emission free solution for generating electricity. Figure 1 presents the summarised economic performance of the shortlisted inter-seasonal energy storage based on the compiled studies. The figure presented in the middle of the bar shows the average cost of each technology within the identified cost range.



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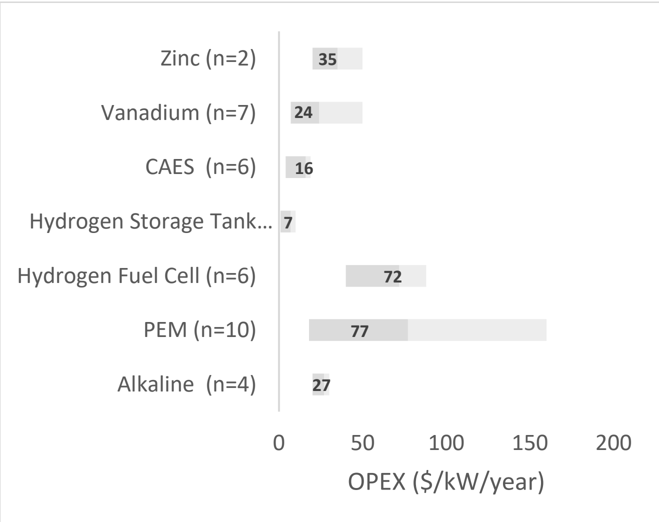


b

Figure 1 Economic performance of the shortlisted potential inter-seasonal energy storage technologies. (a) CAPEX of the shortlisted inter-seasonal energy storage technologies. (b) OPEX of the shortlisted inter-seasonal energy storage technologies. 'n' stands for the selected studies that reported the associated cost.

On average, the CAPEX for CAES is the lowest compared with other technologies, the cost ranges between $400 and $1681 per kW, with the average CAPEX of $949/kW. Regarding the flow batteries, on average, vanadium has a slight lower CAPEX ($1157/kW) than Zinc flow batteries ($1700/kW). The average OPEX of CAES ($18/kW/year on average) is lower than flow batteries; within two types of flow batteries, on average, the OPEX of vanadium ($24/kW/year on average) is lower than zinc-based flow batteries ($35/kW/year on average).

Except for designated potential seasonal energy storage technologies, the economic data of the shortlisted low-carbon dispatchable technologies is also presented in Figure 1.

The CAPEX of alkaline electrolysers ranges between $600 and $1000 per kW. PEM electrolysers are more expensive, ranging between $400 and $1626 per kW. Based on the reported CAPEX from the compiled studies, the average CAPEX of alkaline electrolysers is $757/kW, while the average CAPEX of PEM electrolysers is $1165/kW. On average, the CAPEX of PEM electrolysers is 35% higher than that of alkaline electrolysers. PEM electrolysers have a broader range of OPEX; on average, the OPEX of PEM electrolysers is $77/kW/year, while that of alkaline electrolysers is $27/kW/year.

The CAPEX of hydrogen fuel cells is high, with the minimum cost at $1250/kW and the maximum cost at $2650/kW. The average CAPEX of hydrogen fuel cells is $1949/kW. The OPEX of hydrogen fuel cells ranges between $40 and $88 per kW per year, with an average OPEX of $72/kW/year.

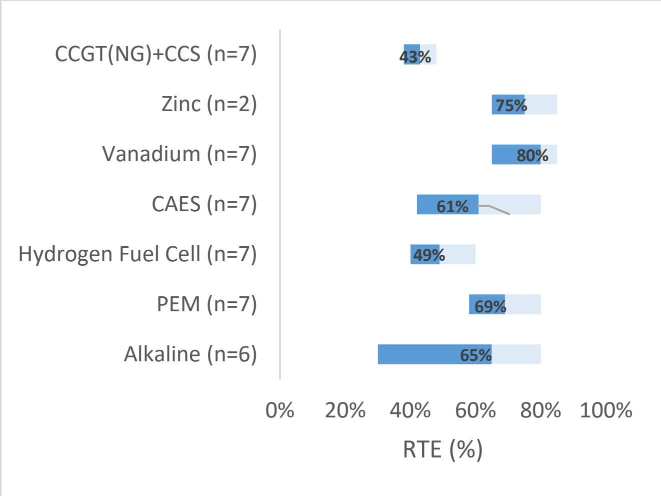
The CAPEX of hydrogen storage tanks (gas, pressurised vessels, standard 400 bar) ranges between $268 and $758 per kg, with an average of $543/kg. The CAPEX difference is due to the size of the storage tank; smaller sizes are much more expensive when converted to unit cost. Hydrogen storage tanks are low-maintenance products; OPEX ranges between $1/kg/year to $10/kg/year, with an average of $7/kg/year.

This research identified only one existing study that discussed the economic performance of using BECCS for seasonal power management. However, this selected study did not report the OPEX of BECCS. Therefore, in this section, we can only report the CAPEX of using BECCS to manage seasonal power supply. The reported CAPEX of BECCS is $5406/kW, which is much more expensive than the other shortlisted storage technologies. Additionally, due to the limited number of studies reporting the cost of BECCS, its associated economic performance is not included in Figure 1.

The CAPEX of CCGT+CCS (natural gas) ranges between $2411 and $2620 per kW, with an average CAPEX of $2516/kW. We found only one study that reported the OPEX of CCGT+CCS (natural gas), which is about $33/kW/year, then the OPEX of CCGT+CCS (natural gas) is not included in Figure 1 (b).

3.2 Literature review results - Economic indicators

The lifespan and round-trip efficiency (RTE) represent the technical performance of the selected potential storage technologies. Figure 2 presents the technical indicators of the selected potential storage technologies based on the compiled studies.



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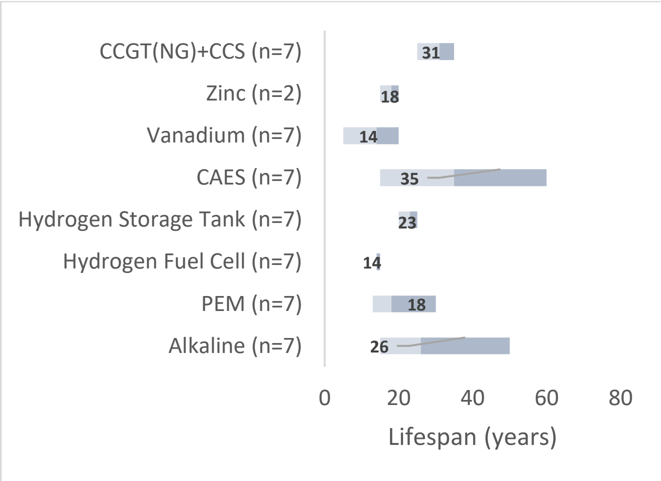

b

Figure 2 Technical Performance of the shortlisted potential inter-seasonal energy storage technologies. (a) RTP of the potential inter-seasonal energy storage technologies; (b) Lifespan of the potential inter-seasonal energy storage technologies. The figure in the middle represents the average RTE or lifespan of each storage technology. 'n' stands for the selected studies that reported the associated cost.

We find that two types of electrolysers, alkaline and PEM, have a similar average RTE of around 70%. Though alkaline electrolysers have a relatively lower bound compared to PEM electrolysers, the upper bound for both is the same, at 80%. The average RTE of the hydrogen fuel cell is about 50%, with only one study showing a higher RTE at 60%. The efficiency of hydrogen tanks was not reported in any of the compiled studies. Considering the entire process of producing hydrogen using electrolysers, and then using hydrogen to regenerate electricity in hydrogen fuel cells, the overall efficiency is around 30-40%. This estimated overall efficiency indicates that only 0.3-0.4 kWh can be regenerated while storing 1 kWh of electricity via hydrogen as a storage medium.
The RTE of CAES ranges between 42% and 80%, with an average of 61% based on the compiled studies. Flow batteries tend to have a higher RTE, ranging between 65% and 85% for both vanadium and zinc batteries. Vanadium flow batteries have a slightly higher average RTE at 80% compared to zinc flow batteries at 75%. The RTE of using CCGT + CCS (fuelled by natural gas) is 43% on average, which is similar to the efficiency of using hydrogen as a medium to balance the power supply.
Alkaline electrolysers have a slightly longer lifespan than PEM electrolysers in general, the average lifespan of alkaline is 26 years, compared to 18 years for PEM electrolysers based on the compiled studies. The selected gas hydrogen storage tank has an average lifespan of 23 years. However, hydrogen fuel cells have a shorter average lifespan of 14 years. Flow batteries also have a shorter lifespan; both vanadium and zinc flow batteries have an average lifespan of around 14 years. CAES has a longer lifespan of 35 years on average, CCGT+CCS (natural gas fuelled) also has a longer lifespan of 31 years on average.

3.3 LCOE estimation results

This section uses the methodology explained in section 2.2 to estimate the LCOE of the shortlisted potential storage technologies. Within the calculation, the average cost, including the CAPEX, OPEX, electricity, hydrogen production and natural gas prices are used to represent a general LCOE of those technologies. Figure 3 presents the estimated average LCOE of the selected storage technologies. While calculating the LCOE of CCGT+CCS, we have applied a higher carbon tax of $0.24/kg to reflect a scenario that prompts a fully green power supply.
In Figure 3, CAES has the cheapest LCOE range compared with other alternative storage technologies for managing the seasonal demand-supply balance within the capacity factor range of 10% to 40%. A vanadium flow battery is another economical solution following CAES for managing the seasonal demand-supply balance, with an LCOE range between 0.22 and 0.44. Zinc is slightly more expensive due to higher CAPEX and OPEX than the vanadium flow battery, with an estimated LCOE range between 0.28 and 0.59. Hydrogen fuel cell is a relatively more expensive solution, with the highest LCOE range between 0.36 and 0.76. However, CCGT+CCS is the most expensive solution to manage the seasonal power demand-supply balance while considering a high carbon price at $0.24 per kg, the estimated LCOE ranges between 0.63 and 1.09.
All the shortlisted storage technologies tend to achieve a lower estimated LCOE at higher capacity factors, with the highest estimated LCOE occurring at a capacity factor of 10%. The estimated LCOE of all selected technologies was reduced by approximately 30% when the capacity factor was increased from 10% to 20%. Subsequently, the estimated LCOE decreased by less than 30% when increasing the capacity factor from 20% to 40%.

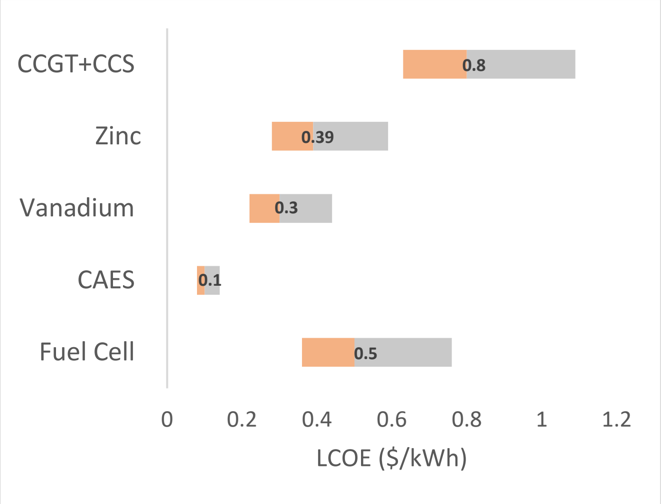

Figure 3 The estimated average LCOE of the selected potential storage technologies

The storage cost of air or hydrogen gas is not included in the LCOE estimation for CAES and hydrogen fuel cells due to the varying costs associated with different storage methods (e.g., storage in salt caverns or tanks). [11] found that retrofitting the existing salt cavern to store hydrogen or air is the most economical storage solution in the UK. This is because the UK has more than 3,000 potential salt caverns in East Yorkshire alone, each capable of storing 122 GWh of hydrogen. Altogether, these caverns can store about 366 TWh of hydrogen, approximately three times the UK's electricity storage plan if hydrogen were the sole energy solution to support a fully green grid [11]. However, storing hydrogen or natural gas in salt caverns can be an expensive solution in countries without extensive underground storage facilities. Section 4.1 continues to discuss how the estimated LCOE of the shortlisted storage technologies changes to reflect changes in fuel prices and considerations of storage costs.

4 Discussion

4.1 LCOE in different prices

4.1.1 LCOE in different fuel prices

This section examines how the estimated LCOE varies with different electricity and natural gas prices. It considers a range of electricity prices from $45 to $100 per MWh, hydrogen production costs from $1 to $3.6 per kg ($0.03 – 0.11/kWh, using LHV = 33.3kWh/kg H2) and natural gas from $11.24 to $67.5 per MWh to discuss the variation in LCOE.

Figure 4 presents the estimated LCOE in different hydrogen production costs. The lowest LCOE is found to be $0.23 per kWh with a CF of 40% and a hydrogen production cost of $1 per kg. The LCOE decreases by at least 16% when hydrogen production costs are reduced from $2.30 per kg to $1 per kg or the cost is down from $3.6 per kg to $2.3 per kg, at a CF of 10%. Additionally, the LCOE can be reduced by up to 30% by increasing the CF from 20% to 30%. The LCOE is reduced by about 30% when hydrogen production costs are lowered from $3.60 per kg to $1 per kg at a CF of 10%. Furthermore, the LCOE can be reduced by up to 52% by increasing the CF to 40% while also reducing hydrogen production costs from $3.60 per kg to $1 per kg.

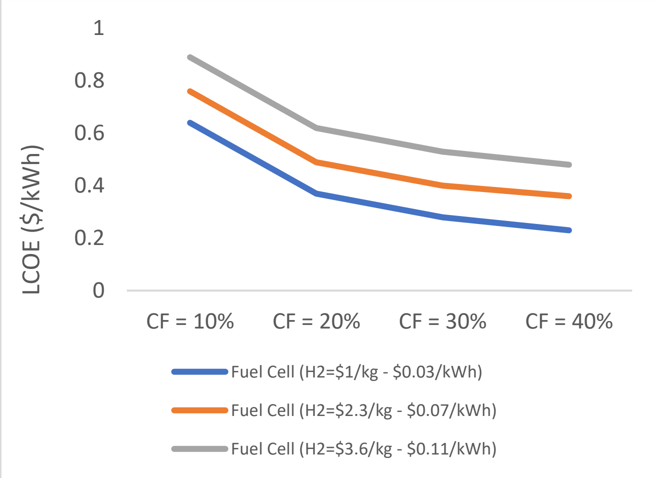

Figure 4 LCOE of hydrogen fuel cells in different hydrogen production costs

Figure 5 presents the estimated LCOE for flow batteries (vanadium and zinc based) in different electricity prices and CFs. It finds that the vanadium flow batteries have a lower LCOE (between 0.07 and 0.32) than zinc flow batteries (between 0.1 and 0.39). The lowest LCOE is observed when using curtailed renewable electricity to charge flow batteries, ranging from $0.07 to $0.28 for vanadium flow batteries and from $0.1 to $0.42 for zinc flow batteries. We assume that the curtailed electricity is sufficient to support flow batteries in generating electricity at a capacity factor of 40%.

In addition, based on Figure 5, the difference in LCOE while using two electricity prices for the charging process becomes more significant as the capacity factor (CF) increases. For example, the difference in LCOE increases grows from 22% to 57% as the capacity factor (CF) rises from 10% to 40% when comparing two electricity prices for the charging process. Using a minimum electricity price of $0.045 per kWh can reduce the LCOE by at least 26% compared to using the maximum electricity price, and by at least 9% compared to using the average electricity price.

The reduction of LCOE is only by about 30% when the electricity price is $100/MWh in the charging process.

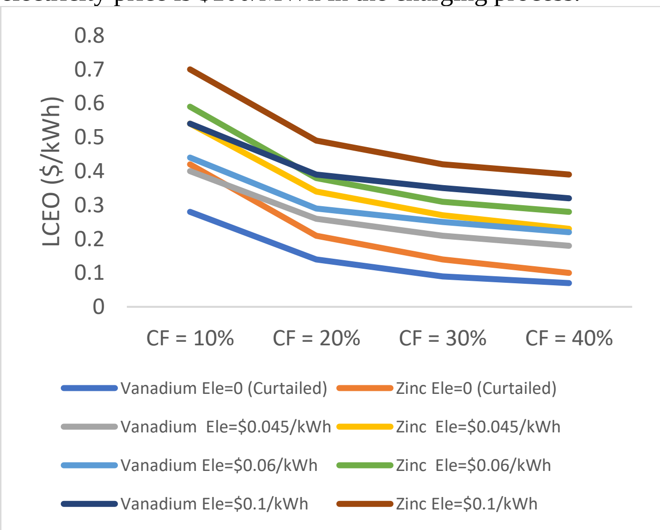

Figure 5 LCOE of flow batteries in different electricity prices

Figure 6 shows LCOE variations of CAES in different electricity prices. The LCOE of CAES ranges between $0.02 and $0.18 per kWh, which is lower than flow batteries across different electricity prices. Except when using curtailed electricity for the charging process, the difference in LCOE is about 20% when using two different electricity prices to charge CAES at the same CF. However, the difference in LCOE can increase up to 61% when comparing the maximum electricity price and curtailed electricity price for charging CAES at the same CF. Different from flow batteries, the difference in LCOE is about 20% when increasing the CF rate while using two different electricity prices (except for the curtailed electricity price) for the charging process.

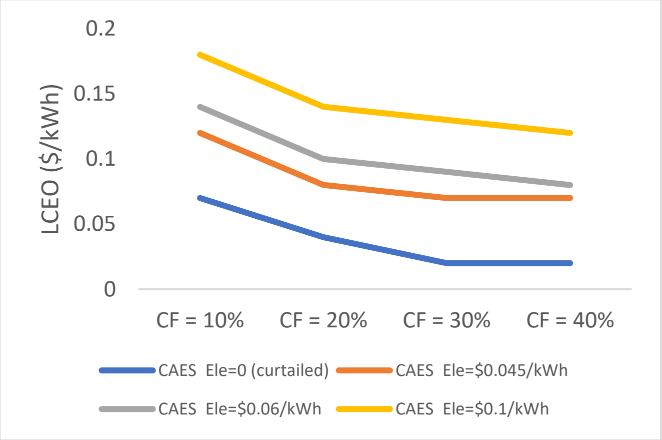

Figure 6 LCOE of CAES in different electricity prices

Figure 7 shows that using CCGT+CCS to manage seasonal power demand balance is an expensive solution than the other selected solutions. Given that the estimated LCOE of CCGT+CCS in different natural gas prices is higher than that of other potential solutions. The range of LCOE for CCGT+CCS varies between $0.47 and $1.35 per KWh. This is higher than the less competitive solution – hydrogen, which ranges between $0.23 and $0.89 per kWh. The difference in LCOE for CCGT+CCS between using two different natural gas prices is less than 30% at the same CF.

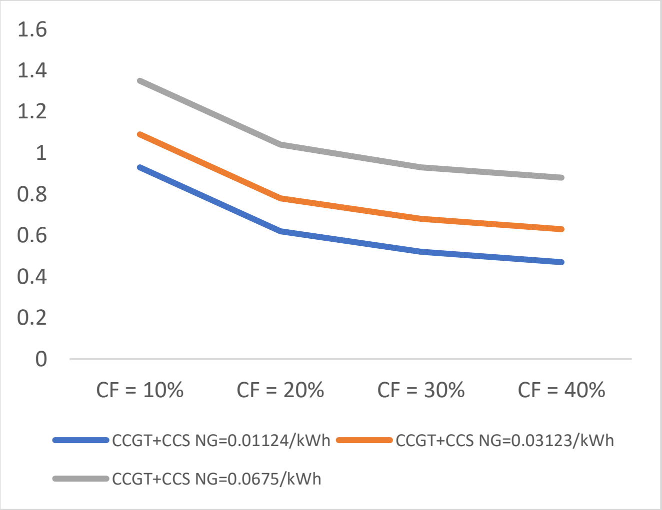

Figure 7 LCOE of CCGT+CCS in different natural gas prices

Based on the results discussed above, the estimated LCOE for CAES is the lowest while using different electricity prices for the charging process among the selected potential inter-seasonal storage options. In general, although the calculated LCOE of flow batteries is lower than hydrogen fuel cells, the future cost of flow batteries may be higher than the reported present price due to limited supply [12]. Uncertainty in the supply chain can lead to cost volatility in both CAPEX and OPEX for flow batteries. There are two major concerns regarding supply chain uncertainties. First, it is uncertain whether flow batteries can be scaled up effectively to manage inter-seasonal power supply balance. Second, it is also uncertain whether flow batteries will be more cost-competitive than hydrogen or other potential inter-seasonal energy storage that do not face supply chain uncertainties in the future energy market.

4.1.2 LCOE in different CAPEX and OPEX

This section examines the differences in LCOE by using the identified minimum, average, and maximum CAPEX and OPEX of the selected potential storage options. Additionally, the calculations use a capacity factor (CF) of 40%, along with the average hydrogen production cost and the average prices for electricity and natural gas.

Based on the findings in Section 3.1, only a single OPEX cost of $33/kW per year for CCGT+CCS is identified in the compiled studies. Consequently, the estimated LCOE for CCGT+CCS under the given conditions comprises only two values. Whereas, three estimated LCOE values are found for the associated minimum, mean, and maximum CAPEX and OPEX of the relevant selected storage options.

Based on Figure 8, the estimated LCOE of CCGT+CCS is the highest among the selected potential energy storage options, ranging between $0.62 and $0.63 per kWh when considering the minimum, mean, and maximum CAPEX and OPEX. Using green hydrogen to manage inter-seasonal power demand-supply balance also results in a higher LCOE, ranging between $0.31 and $0.34 per kWh, second only to CCGT+CCS. The lowest LCOE is found in using CAES to manage inter-seasonal power demand-supply balance, with an estimated range of $0.07 to $0.09 per kWh. The estimated LCOE of vanadium flow batteries is generally lower than that of zinc flow batteries, as the identified CAPEX and OPEX for vanadium flow batteries are lower than for zinc flow batteries.

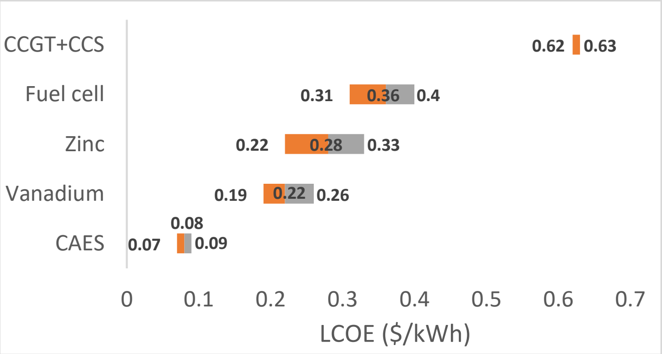

Figure 8 LCOE of the selected potential inter-seasonal storage options under the identified min, mean and max CAPEX and OPEX.

In terms of sensitivity to varying CAPEX and OPEX for the selected potential energy storage options, the estimated LCOE for CAES only increases by 22% from the minimum to the maximum CAPEX and OPEX. Similarly, for hydrogen fuel cells, the LCOE rises by approximately 22% when moving from the minimum to the maximum CAPEX and OPEX. In contrast, the LCOE for flow batteries increases by around 30% when CAPEX and OPEX are adjusted from the minimum to the maximum. The estimated LCOE increases by only 2% from the minimum to the maximum CAPEX and OPEX for CCGT+CCS. Therefore, as discussed above, flow batteries are more sensitive to variations in CAPEX and OPEX compared to the other selected potential storage options. In contrast, the LCOE of CCGT+CCS exhibits the lowest sensitivity to changes in CAPEX and OPEX. Consequently, while reducing CAPEX and OPEX can significantly enhance the economic performance of CAES, hydrogen fuel cells, and flow batteries in managing inter-seasonal power demand-supply balance, a lower CAPEX and OPEX has a more limited impact on the economic performance of CCGT+CCS in this context.

4.2 Ranking results of the potential seasonal storage technologies

Based on the review findings, estimated LCOE, and associated discussions, CAES exhibits the lowest LCOE under all conditions compared to other potential solutions and has the potential to be a cost-competitive option for managing inter-seasonal demand balance. Flow batteries and hydrogen fuel cells follow CAES in terms of cost, while CCGT+CCS is observed to be the most expensive technology for managing the inter-seasonal power demand-supply balance among the selected storage options.

Many existing studies consider green hydrogen to be a competitive solution for inter-seasonal storage due to its longer continuous discharge time and rapid response capabilities [4]. The future cost of green hydrogen production is highly uncertain and depends on unpredictable factors such as expected demand, storage, transportation, and dedicated renewable systems [13], [14]. In addition, [7] projected the cheapest global low-carbon hydrogen at $1/kg ($0.03/kWh) in the future. Even with that price, the estimated LCOE of hydrogen fuel cell is still higher than CAES and flow batteries. Flow batteries, particularly vanadium flow batteries, are characterised by a low LCOE due to their lower CAPEX and OPEX compared to zinc flow batteries. However, the global supply chain for vanadium is volatile, and the estimated LCOE based on the current CAPEX and OPEX may not accurately reflect the future actual costs of vanadium flow batteries. Additionally, flow batteries generally offer medium-duration coverage, which may not be entirely suitable for managing inter-seasonal power demand-supply balance. Furthermore, unlike hydrogen and CAES, flow batteries are still developing their commercial market, with most current projects located in Europe [4].

This research identifies CAES as the most economical solution (with the lowest LCOE) for managing inter-seasonal demand-supply balance among the selected potential storage options. The estimated lowest LCOE of CAES is attributed to its lower CAPEX and OPEX compared to other solutions. However, storage costs are not included in the LCOE estimates; when these costs are considered, the LCOE for CAES is expected to increase. Diabatic CAES projects are already implemented globally, whereas adiabatic CAES is still under research to evaluate its techno-economic and environmental performance [16]. CAES offers good duration coverage, making it practically suitable for managing inter-seasonal demand-supply balance. However, countries with limited underground space might face constraints or reduced economic benefits in adopting adiabatic CAES for this purpose.

CCGT+CCS is identified as the most expensive solution for balancing inter-seasonal demand-supply due to its higher CAPEX and OPEX compared to other solutions. Additionally, this research assumes a high carbon price for fossil fuels in the future, which contributes to the high estimated LCOE of CCGT+CCS. The estimated LCOE suggests that fossil fuels may have a limited role in a net-zero world, especially given the impact of high carbon prices. Dedicated storage options and green hydrogen are likely to offer higher economic benefits than fossil-fuel + CCS systems in power management. Therefore, future energy policy should focus on encouraging the development of suitable storage technologies and green hydrogen rather than relying on fossil fuel-based systems combined with CCS. For example, the UK government has introduced the relevant policy to encourage the investigation and development of long-duration energy storage since 2022 [4], [17], [18], [19].

Based on the discussion results in subsection 4.1.1, lower electricity and hydrogen production costs could enhance economic profits by between 20% and 60%. Therefore, future energy policy should focus on exploring methods to reduce electricity prices and integrate more renewable systems into the grid, aiming for a 100% green power grid characterised by low electricity costs. In addition, future policy should encourage the further development of advanced technologies to enhance the learning curve and reduce the CAPEX and OPEX to the most economical level.

5 Conclusion

The extensive deployment of renewable systems is a fundamental step in transitioning to a fully decarbonised grid. Integrating these systems with energy storage technologies, such as Li-ion batteries, can effectively balance power demand and supply, enabling a stable and affordable energy supply. However, Li-ion batteries are not economically viable for managing the inter-seasonal power supply-demand balance due to their short storage duration. Therefore, it is crucial to explore suitable storage technologies that can effectively manage the inter-seasonal power supply balance, ultimately resulting in a more affordable power supply cost.

This research uses the identified keywords to compile 23 relevant existing studies from three different academic datasets. It finds that potential inter-seasonal energy storage technologies include CAES, flow batteries (vanadium and zinc), and power-to-green hydrogen, as well as two types of low-carbon dispatchable technologies: BECCS and CCGT+CCS (fueled by natural gas). These technologies were studied in the compiled existing studies. However, the existing studies did not explore the relationship between LCOE and different fuel costs, as well as CAPEX and OPEX. Understanding this relationship is useful for identifying the most cost-competitive inter-seasonal energy storage options and providing suggestions to shape future energy policy.

Therefore, this study first reports the different CAPEX and OPEX, as well as technical indicators such as RTE and the lifespan of the selected potential inter-seasonal energy storage technologies. It then develops a method to calculate the LCOE of these storage technologies under various future scenarios with maximum, mean, and minimum fuel prices, CAPEX, and OPEX. The results show that CAES could be the most cost-competitive solution compared to the other selected technologies for managing the inter-seasonal power demand-supply balance, due to its lowest LCOE, ranging between \$0.08 and \$0.14 per kWh. However, the estimated LCOE does not include the cost of storing the required air. In countries where there is insufficient space to store air underground, the LCOE of CAES is expected to increase, potentially making it less cost-competitive compared to other options.

It also finds that using CCGT+CCS (fuelled by natural gas) is the most expensive solution to manage the inter-seasonal power demand with the estimated LCOE between \$0.63 and \$1.09 per kWh. The finding suggests that considering the future high carbon price and high CAPEX of CCGT+CCS, using fossil fuel and CCS is less competitive than other technologies in managing the inter-seasonal power demand supply.

This research also draws several suggestions for the development of future policies. Those policies can effectively encourage the development of inter-seasonal storage technologies and their integration with Li-ion to shape an affordable and stable power supply, with a high level of renewable system integration.

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6 Appendix Tables

Appendix Tables

Table 1 List of Existing Relevant Studies

Title	Publication Year	Technology	Fuel Price	LCOE	Note
Projecting the Future Levelized Cost of Electricity Storage Technologies	2019	Pumped hydro; CAES; Flywheel; Li-ion; Sodium Sulfur; Lead-Acid; Vanadium Flow Batteries; Hydrogen; Supercapacitor	$50/MWh (assumed electricity price)	It projected LCOE of the selected storage between 2030 and 2050	• The study did not discuss the difference in LCOE of different technologies to manage short/medium/inter-seasonal power balance. • Adopted techno-economic data of storage technologies and the used electricity price before 2019, which are likely changed to date.
The role and value of inter-seasonal grid-scale energy storage in net zero electricity systems	2022	Pumped hydro; Li-ion; Power to Methane; BECCS; CCGT+CCS (Natural Gas)	NA	NA	• It did not calculate the LCOE of energy storage technologies. • The study did not discuss the electricity changes associated with different energy storage technologies. • Limited potential inter-seasonal energy storage technologies are discussed in this study. • The associated fuel price (e.g., electricity or natural gas price) is not discussed in this study.
Evaluating emerging long-duration energy storage technologies	2022	CAES, Zinc and Vanadium Flow Batteries	NA	NA	• The study did not discuss LCOE of using storage technologies for managing the long-term (e.g., monthly, seasonally) power balance. • Limited potential inter-seasonal energy storage technologies are discussed in this study. • The relevant electricity prices are not discussed in this study.
A comprehensive review of stationary energy storage devices for large scale renewable energy sources grid integration	2022	All existing Electrochemical, electrical, thermal, mechanical and chemical storage	NA	NA	• The study discussed the techno-environmental performance of the existing storage technologies. However, economic performance has yet to be discussed well.
Long-duration energy storage	2023	Power to X (X refers to potential gases, e.g., hydrogen, methane, ammonia); CAES and pumped hydrogen	NA	NA	• This report found that P2X, CAES and pumped hydrogen storage can potentially be used as inter-seasonal storage. • The report did not discuss the economic performance of those storage technologies.

Table 2 Summary of the compiled studies

Title	Author	Year	Journal	Technology	Application Duration	Fuel Cost ($/kWh)	LCOE	Storage Type
Techno-economic analysis of off-grid PV/wind/fuel cell hybrid system T combinations with a comparison of regularly and seasonally occupied households	Duman & Güler, 2018	2018	Sustainable Cities and Society	PEM - Fuel Cell (5kW Horizon H-5000)	Whole year	Not Reported	Not Reported	NA
				Alkaline - Electrolyser		Not Reported	Not Reported	NA
				Hydrogen tank (pressure vessels)		Not Reported	Not Reported	Gas Storage Tank
Projecting the Future Levelized Cost of Electricity Storage Technologies	Schmidt et al., 2019	2019	Joule	Vanadium Flow Batteries	Inter-seasonal	Not Reported	Not Reported	NA
Power-to-hydrogen as seasonal energy storage: an uncertainty analysis for optimal design of low-carbon multi-energy systems	Petkov & Gabrielli, 2020	2020	Applied Energy	PEM - Electrolyser	Whole year and inter-seasonal	0.15 (Electricity price)	Not Reported	NA
				PEM - Fuel Cell		Not Reported	Not Reported	NA
				Hydrogen tank (pressure vessels)		Not Reported	Not Reported	Gas Storage Tank
The value of seasonal energy storage technologies for the integration of wind and solar power	Guerra et al., 2020	2020	Royal Society of Chemistry	Hydrogen (as a meidum to be stored and discharged)	Inter-seasonal	Not Reported	Not Reported	Gas Storage Tank
Green hydrogen-based energy storage in Texas for	Wikramanayake et al., 2021	2021	IEEE Green Technologies	Electrolyser	Inter-seasonal	0.02 (Electricity Price)	4-8.2	NA

Title	Author	Year	Journal	Technology	Application Duration	Fuel Cost ($/kWh)	LCOE	Storage Type
decarbonization of the electric grid			Conference (GreenTech)					
Techno-economic analysis of balancing California's power system on a seasonal basis: Hydrogen vs. lithium-ion batteries	Hernandez & Gençer, 2021	2021	Applied Energy	Hydrogen Fuel Gas Turbine (HFGT)	Inter-seasonal	Not Reported	1.25-2.3 Green Hydrogen + HFGT	NA
				PEM - Electrolyser		Not Reported	1.25-2.3 Green Hydrogen + HFGT	NA
Levelling renewable power output using hydrogen-based storage systems: A techno-economic analysis	Chen et al., 2021	2021	Journal of Energy Storage	Alkaline - Electrolyser	Inter-seasonal	Not Reported	0.02-0.03 (Germany) 0.04-0.06 (The U.S.)	NA
				Hydrogen Fuel Cell		Not Reported	0.005	NA
				Hydrogen Storage Tank		Not Reported	0.17 (Germany) 0.03 (The U.S.)	Gas Storage Tank
Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids	Hunter et al., 2021	2021	Joule	D-CAES	Long-Duration (including inter-seasonal)	Not Reported	Not Reported	NA
				Vanadium Flow Batteries		Not Reported	Not Reported	NA
				H2 CC/Ethane CC		Not Reported	Not Reported	NA
				Natural Gas Combined		Not Reported	Not Reported	NA

Title	Author	Year	Journal	Technology	Application Duration	Fuel Cost ($/kWh)	LCOE	Storage Type
				Cycle Generation Turbine (CCGT)				
				NG CCGT + CCS		Not Reported	Not Reported	NA
				PEM - Fuel Cell		Not Reported	Not Reported	NA
				PEM - Fuel Cell		Not Reported	Not Reported	NA
				PEM - Electrolyser		Not Reported	Not Reported	NA
Model-based techno-economic evaluation of power-to-hydrogen-to-power for the electrification of isolated African off-grid communities	Schöne et al., 2022	2022	Energy for Sustainable Development	Alkaline - Electrolyser	Inter-seasonal	Curtailed Electricity	Not Reported	NA
				Type - 1 Storage		Not Reported	Not Reported	Gas Storage Tank
				PEM - Fuel Cell		Not Reported	Not Reported	NA
Assessment of hydrogen-based long term electrical energy storage in residential energy systems	Lubello et al., 2022	2022	Smart Energy	PEM - Electrolyser	Inter-seasonal	Not Reported	Not Reported	NA
				PEM - Fuel Cell		Not Reported	Not Reported	NA
				Hydrogen Storage Tank		Not Reported	Not Reported	Gas Storage Tank
A comprehensive review of stationary energy storage devices for large scale renewable energy	Kebede et al., 2022	2022	Renewable and Sustainable Energy Reviews	Vanadium Flow Batteries	Whole year and inter-seasonal	Not Reported	Not Reported	NA

Title	Author	Year	Journal	Technology	Application Duration	Fuel Cost ($/kWh)	LCOE	Storage Type
sources grid integration								
				CAES		Not Reported	Not Reported	NA
Evaluating emerging long-duration energy storage technologies	Shan et al., 2022	2022	Renewable and Sustainable Energy Reviews	CAES (liquid)	Whole year and inter-seasonal	Not Reported	Not Reported	NA
				CAES (adiabatic)		Not Reported	Not Reported	NA
				Zinc Flow Batteries		Not Reported	Not Reported	NA
				Vanadium Flow Batteries		Not Reported	Not Reported	NA
The role and value of inter-seasonal grid-scale energy storage in net zero electricity systems	Ganzer et al., 2022	2022	International Journal of Greenhouse Gas Control	BECCS	Inter-seasonal	Not Reported	Not Reported	NA
				P2M (power to methane)		Not Reported	Not Reported	NA
				CCGT+CCUS (Natural Gas)		Not Reported	Not Reported	NA
A Systematic Comparison of Renewable Liquid Fuels for Power Generation: Towards a 100% Renewable Energy System	Sánchez et al., 2022	2022	Proceedings of the 14th International Symposium on Process Systems Engineering	Methanol combined cycle	Inter-seasonal	Not Reported	0.28-0.35	NA
				Ammonia combined cycle		Not Reported	0.24-0.33	NA
				Methanol fuel cell		Not Reported	0.85-0.96	NA
				Ammonia fuel cell		Not Reported	0.79-0.93	NA

Title	Author	Year	Journal	Technology	Application Duration	Fuel Cost ($/kWh)	LCOE	Storage Type
A techno-economic study for a hydrogen storage system in a microgrid located in baja California, Mexico. Levelized cost of energy for power to gas to power scenarios	Cruz-Soto et al., 2022	2022	Journal of hydrogen energy	PEM - Electrolyser	Inter-seasonal	Curtailed Electricity	0.16	NA
				Hydrogen fuel cell		NA	0.15	NA
				Hydrogen Storage Tank (350 bar, compressed gas technology)		NA	0.005	Gas Storage Tank
Techno-economic analysis of a wind-photovoltaic-electrolysis-battery hybrid energy system for power and hydrogen generation	Li et al., 2023	2023	Energy Conversion and Management	Alkaline - Electrolyser	Whole year	Not Reported	1.85	NA
				Hydrogen Storage Tank (10,000kg capacity)		Not Reported	1.85	Gas Storage Tank
The value of diurnal and seasonal energy storage in baseload renewable energy systems: A case study of Ras Ghareb – Egypt	Hamdi et al., 2023	2023	Journal of Energy Storage	Vanadium Flow Batteries	Durinal	50 (Electrolyte cost)	Not Reported	NA
				PEM - Electrolyser	Inter-seasonal	Not Reported	Not Reported	NA
				Hydrogen Fuel Cell		Not Reported	Not Reported	NA

Title	Author	Year	Journal	Technology	Application Duration	Fuel Cost ($/kWh)	LCOE	Storage Type
Towards 100% renewable energy systems: The role of hydrogen and batteries	Marocco et al., 2023	2023	Journal of Energy Storage	PEM - Electrolyser (40% stack)	Inter-seasonal	Not Reported	Not Reported	NA
				Hydrogen Fuel Cell		Not Reported	Not Reported	NA
				Hydrogen Storage Tank (gas, pressurised vessels)		Not Reported	Not Reported	Gas Storage Tank
Techno-economic study of Power-to-Power renewable energy storage based on the smart integration of battery, hydrogen, and micro gas turbine technologies	Escamilla et al., 2023	2023	Energy Conversion and Management: X	PEM - Electrolyser	Whole year and inter-seasonal	5.4/L (Water)	1. 14/19/23 (cost associated with compression and storage of hydrogen are considered). 2. 6/7/9 (cost associated with compression and storage of hydrogen are not considered)	NA
				Hydrogen storage tank (400 bar, gas)		Not Reported		Gas Storage Tank
				Micro Gas turbine		Not Reported	2/2.2/2.7	NA
Optimal sizing of renewable energy storage: A techno-economic analysis of hydrogen, battery and hybrid systems considering	Le et al., 2023	2023	Applied Energy	PEM - Electrolyser	Inter-seasonal	Not Reported	Not Reported	NA

Title	Author	Year	Journal	Technology	Application Duration	Fuel Cost ($/kWh)	LCOE	Storage Type
degradation and seasonal storage								
				Hydrogen Storage Tank		Not Reported	Not Reported	Gas Storage Tank
				Hydrogen fuel cell		Not Reported	Not Reported	NA
Applications of energy storage systems in power grids with and without renewable energy integration — A comprehensive review	Rana et al., 2023	2023	Journal of Energy Storage	CAES	Whole year and inter-seasonal	Not Reported	Not Reported	NA
				Vanadium Flow Batteries		Not Reported	Not Reported	NA