Energy Reports 14 (2025) 3481–3494

Contents lists available at ScienceDirect

Energy Reports

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

Research Paper

Uncertainty ahead: Should stand-alone energy systems bet on hydrogen backup?

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ARTICLE INFO

Keywords:
Cost uncertainty
Fuel cell
Hydrogen
Levelised cost of energy
Monte Carlo

ABSTRACT

Achieving net zero by 2050 will require decarbonising stand-alone energy applications. Hydrogen is increasingly viewed as a promising energy carrier, but its economic viability remains uncertain due to the lack of consensus on future demand and limited deployment of key components, such as fuel cells, in stationary stand-alone applications. This study investigates whether hybridising batteries with hydrogen can deliver meaningful cost benefits under future cost trajectories. Using a Monte Carlo framework, we simulate 8000 scenarios across constant and seasonal load profiles, varying the capital costs of batteries, fuel cells, electrolysers, and hydrogen tanks based on 2025 estimates and 2050 projections. Our results show that hydrogen integration only becomes economically attractive when multiple component costs decline simultaneously. The fuel cell-to-battery power capital cost ratio emerges as the dominant driver of levelised cost of energy (LCOE) improvements. For constant loads, median LCOE savings remain below 12 %, with more than 5 % savings only achieved when the fuel cell cost is less than 7 times that of the battery. Seasonal nighttime loads offer a wider theoretical LCOE savings range (0–156 %), but substantial gains occur only under unrealistic cost mixes where battery costs remain high and fuel cell costs fall sharply. These findings highlight the sensitivity of hydrogen viability to load profile characteristics and cost interdependencies. They underscore the need for targeted cost reduction strategies, particularly for fuel cells, to justify added system complexity. These findings are important considerations for future investment and policy decisions.

1. Introduction

A rapid transition to renewable energy technologies is essential to limit global warming to no more than 1.5 °C, as outlined in the Paris Agreement, and achieve net zero emissions by 2050 (International Energy Agency, 2021; United Nations, n.d., n.d.). This transition directly supports the United Nation's Sustainable Development Goal 7, which seeks to provide affordable, reliable, sustainable, and modern energy to the 660 million people worldwide who still lack access to electricity (United Nations, n.d.). Achieving net zero by 2050 will require phasing out fossil-fuelled power generation in various sectors including domestic heating, industrial operations and transport (Virah-Sawmy and Sturmberg, 2025). This transition must also apply to off-grid or remote applications, where extending conventional energy infrastructure is often impractical due to technical, economic, or logistical barriers (Jamal et al., 2020). Such locations frequently depend on diesel generators, highlighting the enduring dependence on fossil fuels and the urgent need for cleaner, decentralised energy solutions (Lawrie and Stubenberg, 2025).

Solar photovoltaic (PV) is one the most mature and reliable forms of renewable energy. By 2030, it is projected to become the leading source of renewable electricity, overtaking wind and hydropower (Chadly et al., 2024; International Energy Agency, n.d.). Its rapid installation times and exceptional modularity make solar PV particularly well-suited for deployment in remote, off-grid locations (Victoria et al., 2021; Virah-Sawmy et al., 2025b). Yet to fully harness this potential, energy storage remains essential for maintaining reliable, consistent, and secure supply of renewable energy, particularly due to the inherently intermittent nature of renewable generation (El Haj Assad et al., 2021, p. 14). Battery energy storage is among the oldest, most mature, and scalable energy storage technologies, with proven effectiveness in both grid-connected and stand-alone systems (Akram et al., 2020; International Energy Agency, n.d.; Wang et al., 2012). Despite their versatility, batteries are predominantly used for short-duration energy storage applications (Yang et al., 2024).

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https://doi.org/10.1016/j.egyr.2025.10.026
Received 29 August 2025; Received in revised form 1 October 2025; Accepted 25 October 2025
Available online 31 October 2025
2352-4847/

Nomenclature

Symbol, Description, Parameter or Variable-Indexed by time

$P_{Bat(t)}$	Charing/discharging power of battery at time t (kW), Variable
$P_{EL(t)}$	Electrolyser power at time t (kW), Variable
$P_{FC(t)}$	Fuel cell power at time t (kW), Variable
$P_{Load(t)}$	Load demand at time t (kW), Variable
$P_{UsefulPV(t)}$	Useful PV after curtailment at time t (kW), Variable

Not indexed by time

C_n	Capital cost of n^{th} component, Parameter
$LCOE$	Levelised cost of energy ($AUD/kWh), Variable
LHV_{H2}	Lower heating value of hydrogen (33.33 kWh/kg), Parameter
n	Plant lifetime (20 years), Parameter
O_n	Operation and maintenance cost of n^{th} component, Parameter
r	Discount rate (6 %), Parameter
$t_{replace}$	Time in years, when n^{th} component needs to be replaced, Parameter
y	Plant lifetime, Parameter

Hydrogen as an energy carrier is becoming increasingly popular, and by 2030 its demand is expected to increase by 1.5 times and reach around 150 mega tonnes, with more than one-third coming from new applications (Aba et al., 2024; International Energy Agency, n.d.). Hydrogen has the potential to play an important role in decarbonising hard-to-abate sectors such as steel, chemical, cement and chemical industries (Azadnia et al., 2023; Breyer et al., 2024; IRENA, 2022). Hydrogen offers great potential for seasonal and long-term energy storage (Jia et al., 2025; NREL, n.d.) and can improve self-sufficiency of stand-alone energy systems (Australian Energy Market Commission, n.d.; Bensmail et al., 2015; Hossain Bhuiyan and Siddique, 2025; Lokar and Virtič, 2020; Zhang et al., 2024).

Several studies have explored the hybridisation of battery and hydrogen storage systems, aiming to exploit their contrasting yet complementary strengths. In grid-connected systems, hybrid battery and hydrogen storage can improve stability, increase resilience against extreme events and improve renewable energy utilisation (Kwon et al., 2024; Modu et al., 2025; Wang et al., 2025; Wu et al., 2024). Integrating hydrogen into stand-alone systems has also received increased attention. Studies show that hybridising hydrogen and battery can lower operating costs, reduce curtailment and load shedding, and enhance system resilience (El Shamy et al., 2025; Kilic and Altun, 2023; Rezk et al., 2020; Yahya et al., 2024; Zhang et al., 2025). While some research suggest that hydrogen-based microgrids are usually more expensive (Wei et al., 2025; Yaïci and Longo, 2025), other studies demonstrate that hybridising both technologies can reduce the levelised cost of energy (LCOE) compared to relying on either one alone (Alonso et al., 2024; Dawood et al., 2020; Šimunović et al., 2019; Soomro et al., 2024). Furthermore, in their comprehensive study, Virah-Sawmy et al. evaluated a hybrid hydrogen and battery system across 210 synthetic load profiles, varying in duration, frequency, and timing. Their findings reveal that hydrogen can prevent excessive battery oversizing and improve the LCOE by up to 122 % (Virah-Sawmy et al., 2025a).

The hydrogen economy is often promoted to transport renewable energy across regions. Yet, it currently falls short of cost targets due to high technology costs and efficiency limitations. Moreover, present cost estimates are prone to methodological and data inaccuracies (Aldren et al., 2025). This shows that uncertainties extend beyond future projections and complicate the establishment of a reliable baseline for hydrogen competitiveness.

Uncertainty also plays a critical role in the design and analysis of stand-alone energy systems. Various studies have addressed uncertainties in renewable energy generation, load demand, and market dynamics such as electricity and hydrogen prices (Chang et al., 2024; El Shamy et al., 2025; Lu et al., 2025). Other studies focused on capital cost uncertainties, particularly within hydrogen production and electrolysis; however, fuel cells were often omitted from these analyses (Andrade et al., 2024; Fazeli et al., 2022; Lv et al., 2023; Yates et al., 2020; Zhang and Xu, 2024). This omission is significant, given the substantial uncertainty surrounding future hydrogen demand and its influence on the capital costs of key components namely electrolysers, hydrogen storage, and fuel cells. While fuel cells are predominantly deployed in vehicular applications, their potential in stationary, stand-alone energy systems remains significantly underexplored. One of the key obstacles limiting broader adoption is the high capital cost, which continues to hinder industry progress and delay large-scale deployment (Wilberforce et al., 2016). Virah-Sawmy et al. offered a limited perspective by analysing the impact of a hypothetical 75 % reduction in fuel cell costs on the sizing of a hydrogen/battery hybrid system (Virah-Sawmy et al., 2025a). However, their approach did not account for uncertainties in costs of other components such as electrolyser, hydrogen storage tank and batteries (Virah-Sawmy et al., 2025a). While some earlier studies have considered cost uncertainties associated with hydrogen in stand-alone energy systems, they often focused on individual components, such as fuel cells or electrolysers, without accounting for simultaneous cost reductions across the full individual technologies, including hydrogen storage tanks, and batteries (Khan et al., 2025; Roy et al., 2025). Moreover, these studies typically did not benchmark their findings against battery-only configurations, leaving a critical gap in understanding the comparative value of hydrogen integration. As a result, they fall short of identifying the specific cost thresholds at which hybridising with hydrogen becomes economically advantageous.

Several recent studies have examined hybrid renewable hydrogen systems under different sources of uncertainty, but none have explicitly addressed cost uncertainty in system components. Alghamdi (2025) used a cloud-metaheuristic framework to model wind and network variability, demonstrating that stochastic optimisation significantly influences system performance metrics. Among the evaluated objectives, network customer reliability emerged as the most sensitive to uncertainty, while network power losses exhibited the least sensitivity. Das et al. (2025) evaluated a solar PV/wind hybrid system for a remote site in India, using a techno-economic analysis and sensitivity tests on factors such as state of charge and efficiency. Their results showed that hydrogen demand and component efficiencies drive performance, impacting LCOE and levelised cost of hydrogen (LCOH). In Keshavarz et al. (2025) information gap theory and crow search algorithms were used to optimise a solar PV/fuel cell/diesel system, showing that modest cost increases make the system more robust to reductions and uncertainty in solar radiation. Ahmed et al. (2025) compared multiple storage technologies within solar PV/wind/hydrogen/diesel systems using HOMER Pro, finding vanadium-based batteries to be the most cost-effective, though results were based on fixed cost assumptions. Mulumba and Farzaneh (2025) introduced hydrogen market participation into hybrid hydrogen system optimisation, showing that surplus hydrogen sales can reduce cost of energy (COE) by $0.174/kWh with only a small reduction in reliability. Rozzi et al. (2025) compared mixed-integer linear programming (MILP)_, particle swarm optimisation (PSO), and hybrid optimisation strategies for grid-connected solar PV/battery/hydrogen systems, revealing that MILP-based models achieved lower costs while PSO-based methods reduced emissions, with hybrid models striking a balance between both. Roy et al. (2025) optimised two hydrogen-based system configurations using advanced metaheuristics, showing that including batteries reduced overall costs and that improvements in PV and storage costs strongly influenced economic outcomes. Collectively, these studies advance understanding of hybrid hydrogen systems and address uncertainties in resources, markets, and reliability, but all rely on fixed component cost assumptions, leaving cost uncertainty as a critical gap in the literature.

This study addresses these limitations by systematically evaluating how capital cost reductions across all major hydrogen components influence system LCOE, and by directly comparing hybrid hydrogen and battery systems to battery-only alternatives. In doing so, it enriches the existing literature and provides needed clarity on the conditions under which hydrogen integration becomes both economically viable and technically justifiable, particularly in light of the added system complexity.

This study aims at answering the following questions:

1) To what extent can hydrogen integration improve the LCOE compared to battery-only systems?
2) Among electrolyser, hydrogen storage tank, and fuel cell technologies, which component most significantly influences overall LCOE outcomes?
3) What cost reductions are required across key hydrogen components—electrolysers, storage tanks, and fuel cells—for them to achieve substantial LCOE advantages over battery-only solutions?

2. Methodology

2.1. System modelling

Similarly to our work in Virah-Sawmy et al. (2025a), we consider an off-grid hybrid energy system consisting of a solar PV array, a Proton Exchange Membrane (PEM) electrolyser, a PEM fuel cell, a battery and a hydrogen storage tank. A depiction of the system architecture is provided in Fig. 1. We focus on PEM electrolysers and fuel cells because their fast dynamic response (Agbossou et al., 2001; Liu et al., 2021) and full-range (0–100 %) operation (Nnabuife et al., 2024; Virah-Sawmy et al., 2024) make them ideal for coupling with variable solar PV generation.

A complete mathematical description of the MILP framework and system constraints can be found in Virah-Sawmy et al. (2025a), and in Equations S1-S23 in the Supplementary Materials provided. These details are included there to ensure transparency and reproducibility, while the main text focuses on the elements most critical to the overarching methodological contributions. The sizes of the solar PV array, battery (energy and power), electrolyser, fuel cell, and hydrogen storage tank are co-optimised to minimise the LCOE. During operation, in each hourly interval, solar PV generation is first used to serve the load, charge the battery, or power the electrolyser. Any shortage is met by drawing from the battery or running the fuel cell.

Potential conduction and power-conditioning losses, along with the auxiliary energy required for hydrogen cooling are omitted from this high-level framework, but the reader is pointed to relevant studies (Hu et al., 2024; Klopčič et al., 2024). Incorporating them would be appropriate for detailed, plant-specific design studies, but here they are excluded in the interest of clarity to focus our analysis on capital cost-driven LCOE improvements, dominant cost influences, and the cost-reduction thresholds at which hydrogen becomes competitive with batteries. While their omission slightly underestimates absolute energy requirements, these marginal operational losses have limited influence on the capital cost trade-offs that form the central focus of this study.

The governing power flow equation is provided in Eq. (1) (Feng and Wei, 2024; Hendriks and Sturmberg, 2024).

$$P_{UsefulPV(t)} + P_{FC(t)} = P_{EL(t)} + P_{Load(t)} + P_{Bat(t)} \tag{1}$$

Where $P_{UsefulPV(t)}$ denotes the PV output after curtailment, $P_{FC(t)}$ the fuel cell's delivered power, $P_{EL(t)}$ the electrolyser's power draw, $P_{Load(t)}$ load demand, and $P_{Bat(t)}$ battery's charging/discharging power.

2.2. Objective function

Each individual component of the system is sized to meet the load profile while minimising the LCOE. Eq. (2) provides the LCOE calculation

$$LCOE = \frac{\sum_{n}^{N} C_n R_n \bullet CRF + \sum_{n}^{N} O_n R_n y + \sum_{n}^{N} \frac{C_n R_n}{(1+r)^{t_{replace}}}}{E_{served}} \tag{2}$$

Here, N denotes the total number of component types in the system, and the subscript n, refers to the n^{th} component, such that the summations extend over all technologies considered. C_n and O_n and R_n denote, respectively, the specific capital cost per unit capacity, the operation and maintenance (O&M) cost per unit capacity, and the rated capacity of the n^{th} system component, while E_{served} represents the total energy supplied

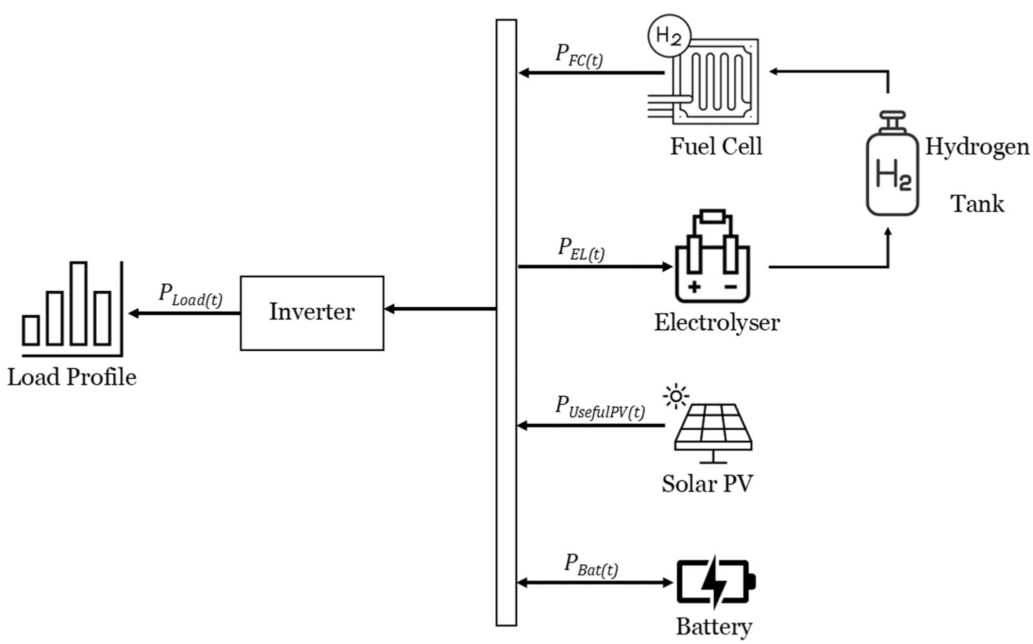


Fig. 1. Architecture of the hybrid energy system.

over the system's lifetime.

The numerator contains three cost streams: (i) capital cost, annualised using the capital recovery factor (CRF) (NREL, n.d.); (ii) annual O&M costs (Olatayo et al., 2018); and (iii) discounted replacement costs (Liu et al., 2024). The third term explicitly applies $(1+r)^{t_{replace}}$ in the denominator to discount the replacement expenditure to present value, where $t_{replace}$ is the year at which the component reaches the end of its technical lifetime (Liu et al., 2024). The replacement cost term in the numerator uses the same unit capital cost C_n as the initial investment, consistent with prior studies (Liu et al., 2024). In line with previous studies, the O&M cost of each component is assumed to be 1 % of its specific capital costs, such that $O_n = 0.01 \quad C_n$ (Eltamaly and Mohamed, 2018; Vartiainen et al., 2020).

The capital recovery factor is then given by (Chauhan and Saini, 2016):

$$CRF = \frac{r(1+r)^y}{(1+r)^y - 1} \tag{3}$$

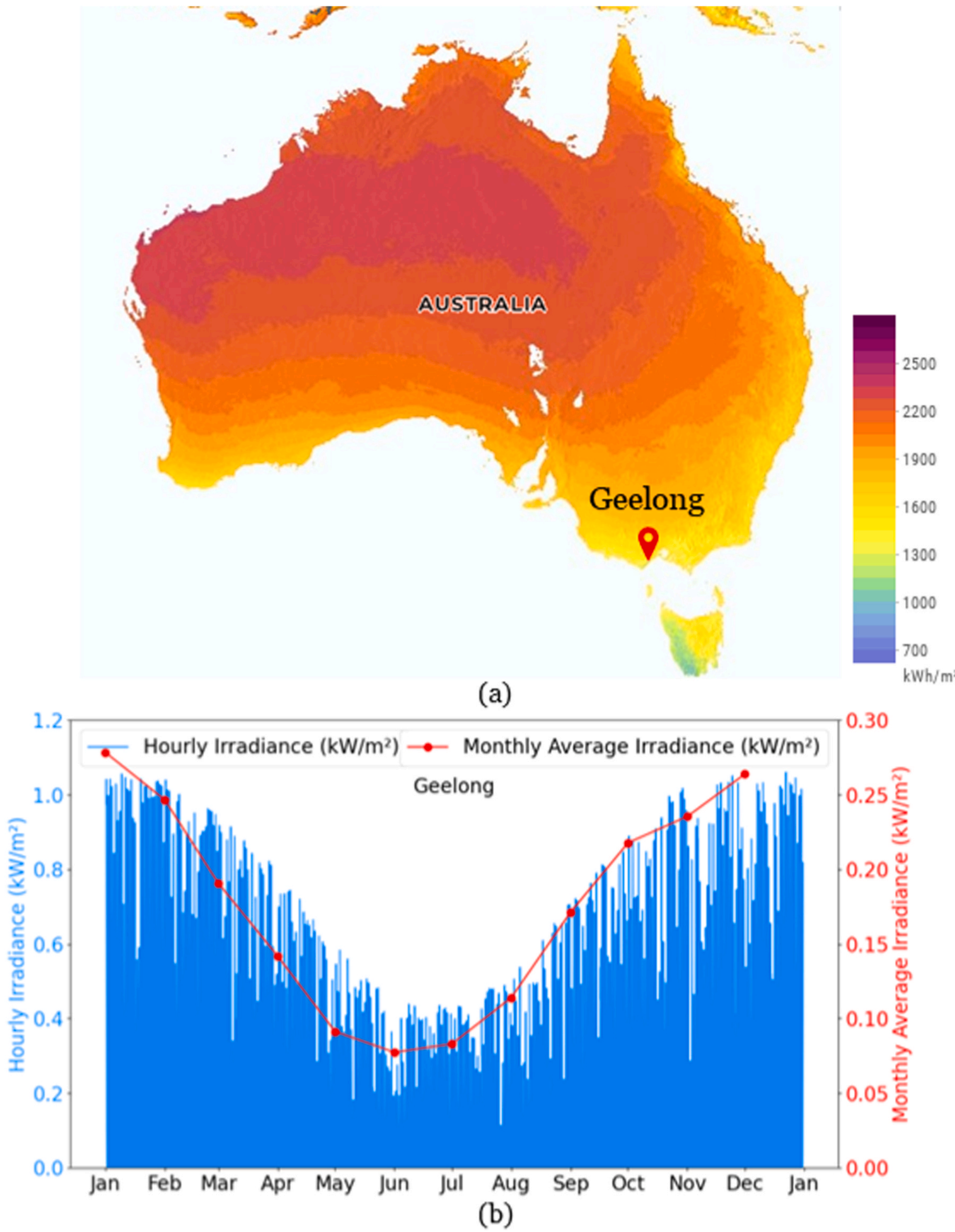
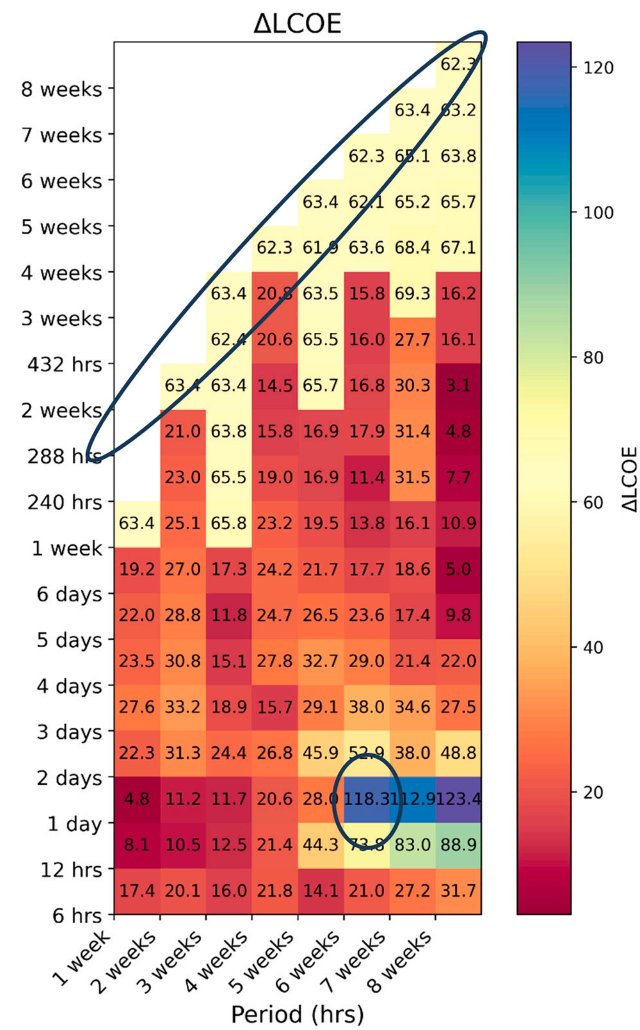


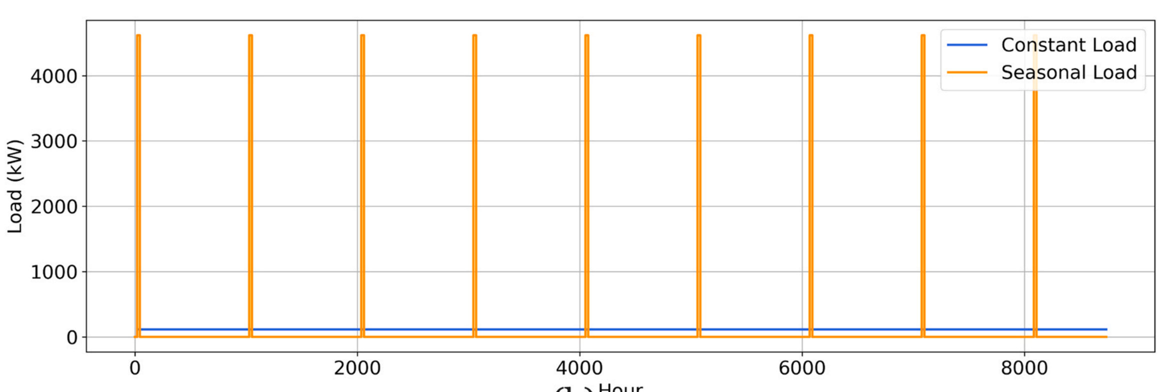
Fig. 2. (a) global solar irradiance (kWh/m2) and location of Geelong; (b) average hourly and monthly solar irradiance (kW/ m2) in Geelong.

The capital recovery factor is applied with a 6 % discount rate, *r*, converting each component's cost into its present value equivalent. The overall project lifetime, *y*, is set to 20 years so that it matches the expected lifespans of both the solar PV array and the hydrogen storage tank.

For tractability under conditions of deep cost uncertainty, this study assumes uniform 10-year lifetimes and a single replacement for batteries, electrolysers, and fuel cells, and does not model performance fade, stack refurbishments, efficiency decay, or availability impacts. These factors are important for detailed plant-specific assessments but are out of scope of our analysis of the potential future cost competitiveness of the two technologies and are therefore left to future work. While such simplifications inevitably bias absolute cost estimates, they are expected to influence both technologies, similarly, allowing us to



(a)



(b)

Fig. 3. (a) ΔLCOE heatmap, adapted from (Virah-Sawmy et al., 2025a), showing the cost improvements from hydrogen integration across various load durations and periods, assuming a 75 % reduction in fuel cell capital cost; (b) The constant and seasonal load profiles.

focus on relative cost dynamics and thresholds under which hydrogen could become competitive with batteries.

2.3. Location and weather data

Like the study from Virah-Sawmy et al., here we choose Geelong, Australia, as the case study location (Virah-Sawmy et al., 2025a). Identified as a potential hydrogen export port, Geelong is poised to play a central role in the development of Australia's hydrogen economy (ARUP, n.d.). Solar irradiance data was obtained from Renewables Ninja ("Renewables.ninja Test," n.d.). Fig. 2 illustrates: (a) the global horizontal irradiance (kWh/m^2) and location of Geelong, (b) the hourly and monthly average solar irradiance (kW/m^2) across a year. In this study we choose to investigate a different year, and hence different solar irradiance data, than Virah-Sawmy et al. (2025a).

2.4. Load profile

In this study, we focus on two distinct synthetic load profiles: a constant load and a seasonal load. These two profiles were selected based on results from our previous work (Virah-Sawmy et al., 2025a), which showed that hydrogen integration can lead to significant LCOE improvements, up to 63 % for the constant load and 118 % for the seasonal load in Geelong. Their corresponding positions on the percentage difference LCOE (ΔLCOE) heatmap are circled in Fig. 3(a), highlighting the substantial cost improvements achievable with hydrogen integration under a scenario where fuel cell costs are reduced by 75 %. Fig. 3(b) shows the temporal structure of these profiles over the year. Both load profiles have an equivalent total energy demand of 1 GWh per year. The constant load has an amplitude of 114 kW, while the seasonal load has an amplitude of 4616 kW. Importantly, these two loads were chosen not only because they represent two of the most hydrogen-favourable cases identified in Virah-Sawmy et al. (2025a), but also because they illustrate two distinct demand characteristics. They therefore provide an upper-bound test case. If hydrogen cannot yield cost benefits under these idealised conditions, it is even less likely to do so under more moderate, real-world load configurations. It is also important to note that this study does not aim to present an optimal stand-alone hybrid system design or to compare hydrogen with all alternative long-duration storage technologies. Rather, we intentionally focus on hydrogen-favourable load scenarios in a location with pronounced solar seasonality (Geelong) to examine, under conditions of great cost uncertainty, whether hydrogen can compete with batteries. Benchmarking against diesel or other storage options such as ammonia, pumped hydro or compressed air energy storage is left for future work. Our results should therefore be interpreted as a boundary test of hydrogen's competitiveness rather than a comprehensive assessment of all stand-alone energy options.

2.5. Cost parameters

To define the cost ranges used in our Monte Carlo analysis, we drew on current capital cost estimates for 2025 and projected 2050 values published by leading energy organisations, including the International Energy Agency (IEA), Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO), the International Renewable Energy Agency (IRENA), and the National Renewable Energy Laboratory (NREL). Our use of 2050 projected costs is motivated by the Net Zero Roadmap (International Energy Agency, 2021). This study does not attempt to forecast future costs. Rather, it investigates how different cost combinations affect system performance and identifies the conditions under which hydrogen components can deliver significant improvements in LCOE compared to battery-only systems.

Table 1 summarises the capital cost estimates for battery, fuel cells, electrolysers, and hydrogen tanks from various literature sources, with projections for both 2025 and 2050. The wide variation in projected capital costs, especially for fuel cells, reflects both the volatility of technology learning curves and the lack of consensus on future hydrogen demand (Abid et al., 2025; Fazeli et al., 2022; Odenweller and Ueckerdt, 2025), underscoring the need for a probabilistic framework that can rigorously assess cost-driven design sensitivities. This uncertainty strengthens the legitimacy of this study, which aims to reveal how different cost trajectories might influence the economic viability of hydrogen and battery hybrid energy systems.

While learning rate approaches have commonly been used to explore cost uncertainties in mature technologies such as solar PV or batteries (Bolinger et al., 2022; Kim et al., 2019; Reza et al., 2023; Ziegler et al., 2021; Yang et al., 2025), such models rely on clear deployment trends and relatively stable demand projections. In contrast, the limited market maturity of stand-alone fuel cell systems, and the lack of consensus surrounding long-term hydrogen demand, make it difficult to apply such conventional learning rate methodology. Therefore, we use a Monte Carlo approach, allowing capital costs to vary across plausible future scenarios and enabling a more flexible, exploratory analysis of each individual component's economic impacts.

For our Monte Carlo simulations, we define the cost range for each component by using the minimum projected cost for 2050 as the lower bound, and the maximum estimated cost for 2025 as the upper bound. Projected costs are sampled using normal distribution. This determines the frequency with which certain costs are drawn but does not imply that technology cost trajectories themselves follow a normal distribution. The Monte Carlo approach is designed to span the full range of possible costs, thereby exploring uncertainty with a minimal set of underlying assumptions. This framework aims to transparently assess how different costs could impact the overall system configuration, rather than predict precise statistical shape of future cost trajectories. Projected costs for hydrogen tanks are highly uncertain, and no robust estimates were available beyond 2024. To provide a credible range for exploration, we therefore adopted conservative bounds. The upper bounds were taken from the two near-term estimates reported (Moran et al., 2024), while the corresponding lower bounds were set at 50 % of these values to provide a conservative range for long-term uncertainty exploration. This choice does not imply that costs will necessarily halve by 2050, but instead provides a transparent boundary condition that allows our Monte Carlo analysis to span a broad uncertainty range and assess the influence of tank costs on overall system outcomes.

No correlations between component costs were imposed in this study. While such correlations may exist (Ozkan et al., 2024), our

Table 1
Cost summary for 2025 and 2050.

Battery ($/kWh)		Fuel cell ($/kW)		Electrolyser ($/kW)		Hydrogen tank ($/kg)	
2025	2050	2025	2050	2025	2050	2025	2050
409 (IRENA, n.d.)	180 (International Energy Agency, 2024)	7193 (Graham et al., 2024)	45 (International Energy Agency, 2024)	1050 (IRENA, 2020)	201 (De Maigret et al., 2022)	612 (Moran et al., 2024)	306
465 (Cole and Karmakar, 2023)	244 (Graham et al., 2024)		4532 (Graham et al., 2024)	2248 (Graham et al., 2024)	229 (Graham et al., 2024)	1820 (Moran et al., 2024)	910
567 (Graham et al., 2024)				3000 (International Energy Agency, 2025)	780 (International Energy Agency, 2024)		

objective here is not to forecast specific joint cost trajectories but to assess system behaviour under a wide range of plausible cost outcomes. By treating costs independently, we minimise assumptions and ensure that the Monte Carlo framework transparently explores the full uncertainty space rather than narrowing it through speculative relationships.

The battery was modelled with separate power and energy components, which were independently sized in the optimisation. In this study, the power component cost was assumed to be twice that of the energy component. This assumption is consistent with common practice in the literature, where separating power and energy costs enables more flexible sizing (Anuradha et al., 2024; Gholami et al., 2024), and with findings that battery power components are generally more expensive than energy components (Cole and Karmakar, 2023). To maintain continuity with previous work that this study extends, we adopted a 2:1 cost ratio between power and energy (Virah-Sawmy et al., 2025a). We still acknowledge that the exploration of power to energy cost ratio may be undertaken in future work. Even though our study focuses on energy storage, solar PV is still optimally sized while its capital cost remains fixed at a 2050 projected cost of $AUD 678 across all simulations. While solar PV sizing remains subjected to cost optimisation, the system must ultimately deploy sufficient generation capacity to reliably meet demand and support storage charging. Therefore, even with variations in solar PV costs, the system is fundamentally constrained by its need to cover the load demand, causing the relative economic difference between battery-only and hybrid configurations only marginally sensitive to solar PV pricing. By fixing the solar PV CAPEX, the analysis provides a consistent baseline from which the influence of storage cost uncertainties can be more clearly evaluated.

All cost values were converted to Australian dollars (AUD) for consistency. Reported values in USD were converted using an exchange rate of 1 USD = 1.5 AUD, while values reported in Euros were converted using 1 EUR = 1.75 AUD based on exchange rates from May 2025 published by the Australian Taxation Office (Australian Taxation Office, n.d.). The use of fixed exchange rates is a common practice in techno-economic studies to ensure comparability across different data sources (Fazeli et al., 2022). Nevertheless, exchange rate fluctuations and inflation dynamics can impact cost benchmarks and, consequently, comparative LCOE outcomes (Alonso-Travesset et al., 2023; Iorember et al., 2024; Ozturk et al., 2024). Since this study is primarily concerned with the relative cost of hydrogen–battery versus battery-only systems, such effects would be expected to influence both technologies in a broadly similar way and are therefore less critical to the comparative results. These effects are not considered in this study but may be incorporated in future work.

For each load profile, we ran 2000 scenarios using Monte Carlo for hybrid hydrogen and battery systems. We then performed 2000 more scenarios using the same battery cost parameters, but without hydrogen. To evaluate the relative benefit of adding hydrogen to a battery-only system, we define the percentage change in levelised cost of energy (ΔLCOE) as the absolute difference between the two LCOE values, normalised by their average:

$$\Delta LCOE = \left| \frac{LCOE_{\text{with battery only}} - LCOE_{\text{with battery and hydrogen}}}{\left(\frac{LCOE_{\text{with battery only}} + LCOE_{\text{with battery and hydrogen}}}{2} \right)} \right| \times 100\% \tag{4}$$

Fig. 4 illustrates the different Monte Carlo generated scenarios, with capital cost of the respective components shown on the vertical axis. The green line represents the median. As seen, the fuel cell has the widest capital cost spread, and thus a broader uncertainty range, translating into a disproportionately large impact on the overall system LCOE.

3. Results

3.1. Constant load profile

This sub-section covers the results for the constant load profile.

Fig. 5 illustrates how the ΔLCOE varies with the capital cost of (a) the battery energy, (b) the fuel cell, (c) the electrolyser, and (d) the hydrogen tank, across the 2000 Monte Carlo simulations for the constant load profile. LCOE improvements vary between 0.004 % and 20 %. In each subplot, the light blue circles represent individual simulation results. The dotted and solid vertical lines respectively indicate the 2025 and 2050 capital cost projections, thereby providing a visual analysis to near and long-term thresholds.

Comparing the subplots, the most noticeable effect is observed with the battery CAPEX, where a reduction in cost leads to a decline in ΔLCOE improvements. This inverse relationship suggests that as batteries become cheaper, the economic benefit of hybridising with hydrogen, under the constant load profile considered here, decreases. In

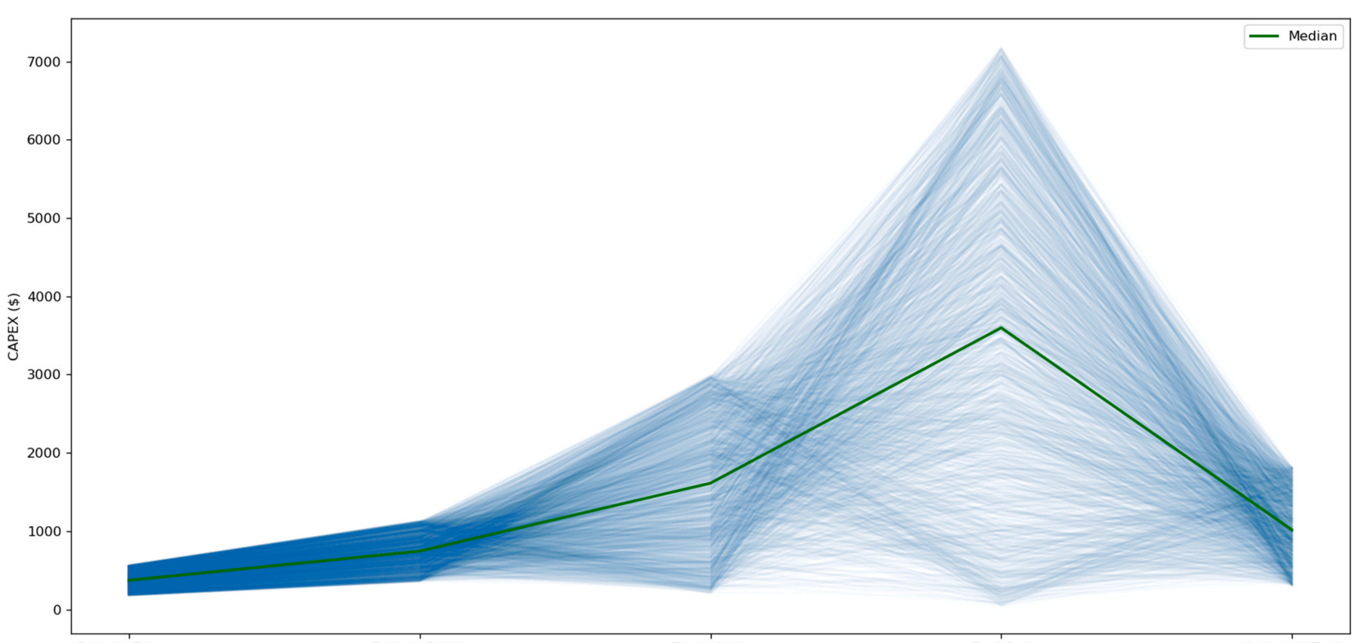


Fig. 4. Illustration of the different combinations of Monte Carlo simulations.

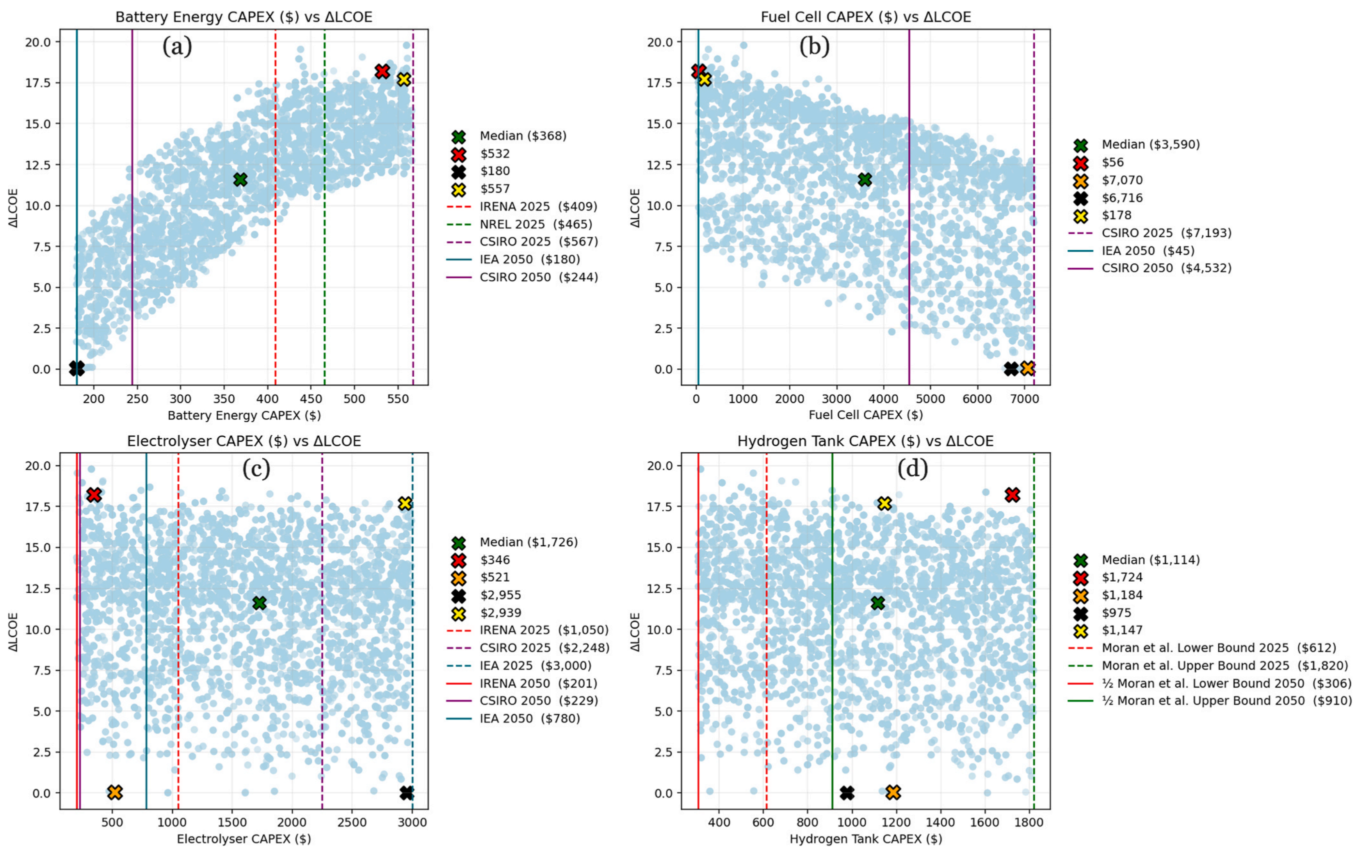


Fig. 5. Constant load profile ΔLCOE against (a) battery energy capex, (b) fuel cell capex, (c) electrolyser capex, and (d) hydrogen tank capex.

comparison, in Fig. 5(b), the fuel cell CAPEX exhibits a positive correlation with ΔLCOE, where lower fuel cell costs result in greater LCOE improvements. This highlights the fuel cell's key role in enabling hydrogen to contribute meaningfully to stand-alone hybrid systems. Regarding Fig. 5(c) and (d), no consistent trend emerges, indicating that within the assessed cost ranges, the electrolyser and hydrogen tank have limited impact on the ΔLCOE.

To further illustrate the range of outcomes, five scenarios are highlighted on each subplot. The median (green cross), low ΔLCOE (orange cross), and high ΔLCOE (red cross), illustrating the span of economic impact under different cost assumptions. The green cross illustrates a scenario where each component's capital cost is reduced by approximately 50 % relative to 2025 estimates. Under these conditions, hybridising with hydrogen yields up to 12 % improvements in LCOE, showing moderate economic benefits when all technologies advance in parallel. The orange cross illustrates a scenario where the battery cost aligns with IEA's 2050 projections while the fuel cell cost remains at CSIRO's 2025 estimates, yielding a low ΔLCOE of less than 1 %. This suggests that under such conditions, and for the constant load profile investigated, the added complexity of hydrogen integration offers limited value. In contrast, the red cross represents a scenario where fuel cell cost falls to CSIRO's 2050 projections while battery cost remains close to 2025 levels, yielding a high ΔLCOE of more than 18 %. This scenario illustrates the key role of fuel cell cost reductions in unlocking the economic potential of hydrogen and battery hybrid systems.

To test whether the low electrolyser cost in the red and orange crosses was driving the observed outcomes, two additional scenarios were plotted: the black and yellow crosses. The yellow cross represents a scenario with high electrolyser cost (near its 2025 upper estimates), low fuel cell cost (near its lower bound 2050 estimates), and high battery cost (near its upper bound 2025 estimates), yielding high LCOE improvements (>17 %), while the black cross represents a scenario with high electrolyser cost (near its 2025 upper estimates), high fuel cell cost (near its 2025 upper estimates), and low battery cost (near its lower 2050 estimates), yielding low LCOE improvements (∼0.015 %). These contrasting configurations confirm that electrolyser cost has a negligible influence on ΔLCOE in this context, and that battery and fuel cell costs remain the dominant drivers. The black cross illustrates a case where even if the capital costs of hydrogen components are very high, the optimisation still introduces extremely small hydrogen subsystems. In this case, the electrolyser and fuel cell capacities are small (e.g., ∼0.10 kW and ∼0.92 kW respectively), so their cost contribution is minimal. At the same time, their inclusion enables a reduction in both battery power and energy capacity, which drives down the overall system cost. As the optimisation is focused solely on cost minimisation and does not penalise added complexity or impose minimum component sizes, it will always favour such marginal hybrid configurations whenever they deliver even a very small improvement in LCOE. This explains why the ΔLCOE often remains consistently positive across all scenarios.

Under a constant load scenario, substantial LCOE improvements are only achieved when fuel cell costs significantly decline while battery costs remain relatively high, a scenario which is unlikely. As battery costs continue to fall, hybridising with hydrogen only provides marginal benefits, making the added complexity less economically justifiable.

From Fig. 5 we see that the battery and fuel cell are the dominant players in the system's economics. We thus extend our analysis to examine how the relative cost of the fuel cell to battery power affects the viability of hydrogen integration and present Fig. 6, a box plot of ΔLCOE against fuel cell to battery power ratio, under the constant load scenario. The plot reveals that when the fuel cell cost remains within 7 times that of the battery power component, integrating hydrogen consistently yields more than 5 % LCOE improvements, indicating strong economic viability. However, as the ratio increases beyond 7, the cost benefit decreases, with median ΔLCOE falling below the 5 % benchmark for ratios greater than 11. This trend highlights the key role of fuel cell affordability, relative to the battery, in determining the feasibility of

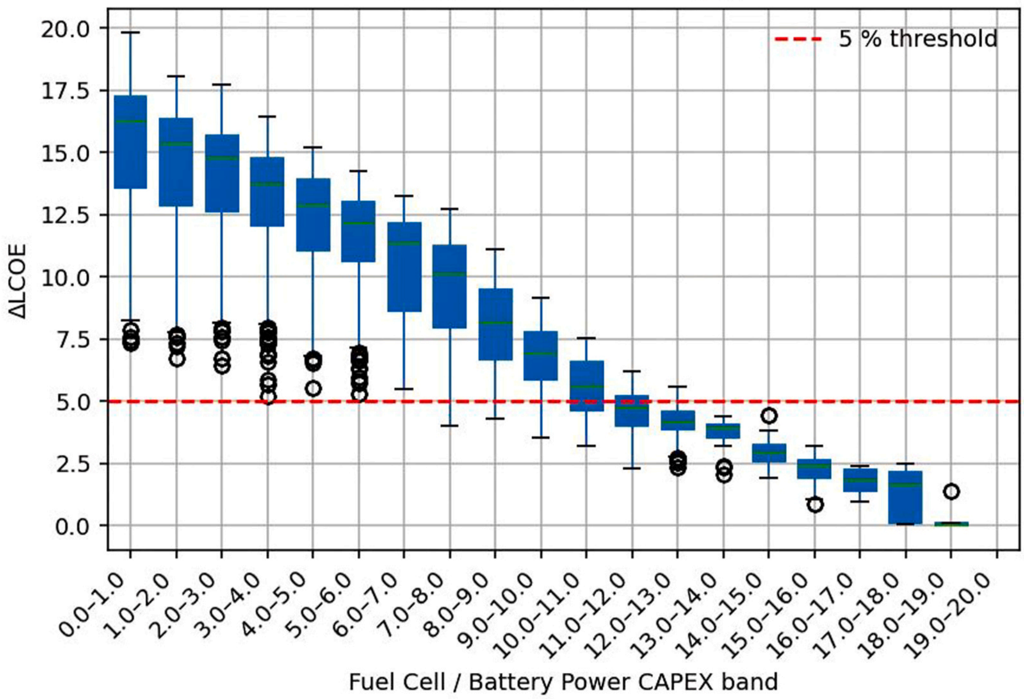


Fig. 6. Box plot illustrating how the ΔLCOE, under the constant load scenario, varies with fuel cell vs battery power capital cost ratios.

hybrid hydrogen and battery systems. Based on current 2025 cost estimates, the capital cost ratios between fuel cell and battery power range between 6.3 and 8.8, sitting near the critical threshold of 7 identified in Fig. 6. This proximity highlights the marginal economic viability of integrating hydrogen under present conditions. It also suggests that if battery costs continue to decline more rapidly than fuel cell costs, or if fuel cell costs remain stagnant, hybridising with hydrogen will yield less than 5 % LCOE improvements. From a policy perspective, these findings

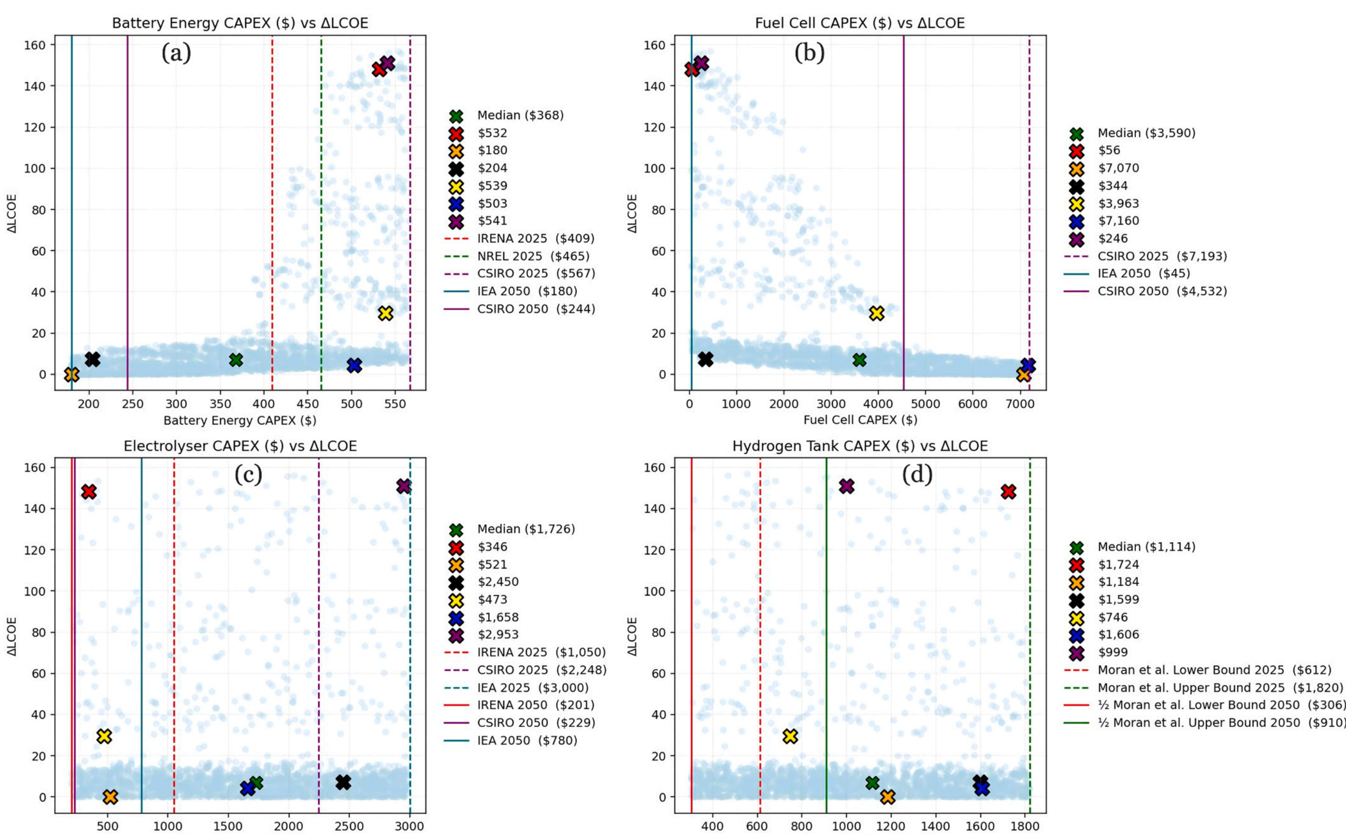


Fig. 7. Seasonal load profile ΔLCOE against (a) battery energy capex, (b) fuel cell capex, (c) electrolyser capex, and (d) hydrogen tank capex.

show the importance of cost reduction strategies for fuel cell technologies. To unlock the full economic potential of hydrogen integration in stand-alone applications, fuel cell costs must be brought within a competitive range relative to battery systems. This aligns with broader decarbonisation goals and supports the case for continued investment in fuel cell innovation, manufacturing scale-up, and market incentives.

Figure S1 in the Supplementary Materials is a heatmap illustrating how the ΔLCOE, under the constant load scenario, varies with different fuel cell and battery power capital costs. It also shows that the 2000 Monte Carlo simulations were enough to investigate the full spectrum of cost combinations.

3.2. Seasonal load profile

This sub-section covers the results for the seasonal load profile. We assumed that the seasonal load occurs at night, to fully focus on the impact of energy storage.

Fig. 7 illustrates how the ΔLCOE varies with the capital cost of (a) the battery energy, (b) the fuel cell, (c) the electrolyser, and (d) the hydrogen tank, across the 2000 Monte Carlo simulations for the seasonal load profile. Compared to the constant load profile in Fig. 5, the seasonal load profile in Fig. 7 exhibits a distinctly different ΔLCOE dispersion pattern. In the constant load profile scenario, the data points are more uniformly distributed along the vertical axis but reflect a moderate range of ΔLCOE spanning from 0.004 % to 20 %. In comparison, the seasonal load plots show a pronounced clustering of points near the 20 % ΔLCOE bound. Despite this visual compression, the seasonal load scenarios yield a much broader range of ΔLCOE, spanning from 0 % to 156 %, indicating that under certain capital cost conditions, integrating hydrogen can unlock significant cost benefits.

In particular, the battery and fuel cell components continue to exert the most significant influence on ΔLCOE. Plotted side by side, the battery and fuel cell capital cost sensitivity curves exhibit a near mirror-image relationship, with ΔLCOE improvements increasing as battery costs rise but diminishing as fuel cell costs increase. This shows that hydrogen integration is most economically advantageous when battery technologies are expensive and fuel cell costs are minimised. In the battery subplot, the vertical spread of ΔLCOE values shifts towards the right, indicating that higher battery capital costs result in greater LCOE improvements. On the other hand, the vertical spread of ΔLCOE values in the fuel cell subplot shifts towards the left, showing that lower fuel cell costs are necessary to achieve substantial (>20 %) LCOE improvements. In contrast, the hydrogen tank and electrolyser plots remain more vertically dispersed, with less pronounced directional trends, suggesting a weaker correlation between their capital costs and ΔLCOE outcomes. These patterns reinforce the dominant role of battery and fuel cell economics in shaping system viability. A broad analysis of the subplots reveals that if the battery cost remains below $380/kWh, less than 20 % savings are achieved, regardless of the individual hydrogen components' costs.

Among the individual custom selected points. The green cross represents the median scenario, where the components are approximately halved relative to their highest 2025 estimates. In this scenario, only the fuel cell falls within its projected 2050 thresholds, while the battery, electrolyser and hydrogen tank remain above. Despite this cost reduction across all components, only 7 % LCOE improvement is achieved. Even if the fuel cell falls within its 2050 cost threshold, it remains too expensive relative to the battery in this scenario, limiting its ability to bring more significant cost savings.

The red cross represents a scenario in which exceptionally high LCOE improvements are achieved. In the red cross scenario, the battery cost remains near its highest 2025 estimate, while the fuel cell and electrolyser costs are near their lowest 2050 projected values. Such cost combination results in more than 145 % LCOE improvements, highlighting the theoretical potential of integrating hydrogen under aggressive cost reductions. Yet, such a scenario is economically unrealistic. It assumes a dramatic decline in the fuel cell and electrolyser costs, while the battery cost remains disproportionately high. This creates an artificial advantage for hydrogen, that is unlikely to happen under balanced market conditions. To test whether the low electrolyser cost in the red cross was disproportionately influencing the outcome, an additional scenario represented by the purple cross was added. In this case, the electrolyser cost is set near its highest 2025 estimate, while the fuel cell cost remains very low (near its 2050 lower bound) and the battery cost remains near its highest 2025 estimate. Despite the high electrolyser cost, the system still yields a ΔLCOE improvement exceeding 150 %, confirming that the fuel cell and battery costs are the dominant drivers of economic performance. This sensitivity test reinforces that the red cross's high LCOE gain is not primarily due to the cheap electrolyser, and that under seasonal load conditions, substantial savings can still be achieved even when electrolyser costs remain very high as long as the fuel cell cost is very low and the battery cost remains high. Again, this is unlikely to happen under realistic market trajectories, as it assumes a future in which fuel cell technologies become drastically cheaper than batteries. While useful for isolating sensitivities, such a scenario remains speculative and should not be interpreted as a likely pathway for hydrogen integration.

In contrast, the orange cross illustrates a scenario where no LCOE savings are achieved. Here, the battery cost is near its lowest projected 2050 estimate, the electrolyser falls within its 2050 cost threshold, but the fuel cell remains near its highest 2025 estimate, resulting in no economic benefit from hydrogen integration. This scenario illustrates the disproportionate influence of fuel cell costs on overall hydrogen integration viability. Unless substantial cost reductions in fuel cell are achieved, hydrogen integration will fail to deliver meaningful economic benefits, even when other hydrogen components reach favourable cost projections.

The black cross illustrates a scenario where approximately 8 % savings are achieved. In this case, the fuel cell and battery align with their optimistic 2050 estimates, while the electrolyser and hydrogen tank remain within their 2025 cost thresholds. Despite the substantial cost reduction in fuel cell, the overall savings remain below 10 %. When considered alongside the orange cross scenario, where fuel cell costs prevent any LCOE improvement, these results reveal that while reducing fuel cell costs is essential to enable savings, such reductions alone are insufficient to unlock substantial economic benefits. This also highlights that under seasonal load conditions, electrolyser cost plays a more pivotal role than under constant load scenarios. During extended periods of no load demand, the electrolyser operates intensively to store excess energy for later use, making its cost a more dominant factor in overall system economics.

The yellow cross represents a scenario where the fuel cell, electrolyser, and hydrogen tank all fall within their optimistic 2050 cost projections, while the battery cost remains high, near its highest 2025 estimate. Such conditions give rise to approximately 30 % LCOE savings. Due to the high battery cost, substantial savings are achieved, indicating that the battery plays a dominant role on system economics. This scenario, like the red cross scenario, is unlikely to occur under balanced market conditions, as it assumes a highly favourable cost trajectory for hydrogen components while battery costs remain stagnant. Nevertheless, it illustrates the strategic value of hydrogen integration in offsetting high battery costs when such disparities do arise.

The deep blue cross reveals a scenario in which both battery and fuel cell costs remain high, near their upper 2025 estimates. The electrolyser cost, on the other hand, is reduced to approximately half its 2025 value. Despite the substantial cost reduction in the electrolyser, the system yields only a 4 % improvement in LCOE. This result reinforces the limited influence of electrolyser cost alone in driving economic performance, and once again confirms the dominant role of the fuel cell in enabling more substantial LCOE reductions. This scenario illustrates that without concurrent cost declines in the fuel cell, even aggressive reductions in other hydrogen components offer minimal economic benefit.

Fig. 8 is a box plot of ΔLCOE against fuel cell to battery power ratio, under the seasonal load scenario. The box plots shows that when the fuel cell to battery power capital cost ratio exceeds 2, the median ΔLCOE consistently falls below 20 %. The plot also reveals a clear threshold effect: when the fuel cell is more than 4 times as expensive as the battery, hydrogen integration consistently yields less than 5 % ΔLCOE improvements. This means that under current 2025 cost conditions, where the fuel cell to battery power capital cost ratio varies between 6.3 and 8.8, less than 5 % improvement in LCOE would be obtained.

This marginal benefit calls into questioning the economic justification for added system complexity under such cost conditions. Compared to Fig. 6 where the constant load profile tolerated cost ratios up to 7 before falling below the 5 % improvement threshold, the seasonal load scenario imposes a stricter constraint. For seasonal demand profiles, the fuel cell must remain within a cost ratio of 4 relative to the battery to deliver meaningful (>5 %) savings. Although the total annual energy demand remains similar across the load profiles analysed in this study, the seasonal load scenario has a much higher peak load demand approximately 40 times greater than the constant load scenario. As the peak load occurs during nighttime, the system relies fully on the energy storage components to satisfy the load demand. As such, the fuel cell size must be sized significantly larger to meet these concentrated seasonal nighttime loads, thereby increasing capital costs. Therefore, more aggressive cost reductions are required for hydrogen integration to deliver meaningful economic benefits under seasonal conditions.

These contrasting results illustrate the sensitivity of hydrogen viability to load profile characteristics, demonstrating that seasonal variability tightens the economic tolerances for component cost ratios and demands more favourable fuel cell pricing to justify hybridisation. Moreover, insights from Fig. 7 show that even when the fuel cell capital cost is below \$1000/kW, well within its optimistic 2050 projection, significant (>20 %) LCOE savings are not guaranteed.

Figure S2 in the Supplementary Materials is a heatmap illustrating how the ΔLCOE, under the seasonal load scenario, varies with different fuel cell and battery power capital costs. It also shows that the 2000 Monte Carlo simulations were enough to investigate the full spectrum of cost combinations.

3.3. Summary of main findings

Our Monte Carlo analysis reveals that in stand-alone energy systems, hybridising battery with hydrogen only become economically attractive when multiple hydrogen components costs decline at the same time, with relative fuel cell to battery power capital cost emerging as the key factor. Across 4000 Monte Carlo runs, a constant load yields median savings below 12 % and never above 20 %, while a seasonal nighttime load opens a theoretical 0–156 % range but achieves large gains only under unrealistic price mixes in which batteries stay expensive and fuel cell and electrolyser costs drastically fall to their projected 2050 values. Under the constant load profile, achieving more than 5 % LCOE improvements requires the fuel cell to battery power capital cost ratio to remain below 7, a threshold that reduces to 4 under the seasonal load. When battery costs fall below roughly \$380/kWh under the seasonal load profile, hydrogen's integration consistently yields less than 20 % LCOE improvements. Moreover, aggressive fuel cell cost reductions alone are insufficient under seasonal demand where the electrolyser cost gains prominence due to its intensive operation during periods of surplus generation. Median ΔLCOE results show that hydrogen's cost advantage fades quickly as the fuel cell to battery power capital cost ratio increases. Under the constant load scenario, median savings exceed 5 % only while that ratio stays below 11, then fall below 5 % once the ratio increases. In the seasonal load scenario, median ΔLCOE falls below 20 % as soon as the ratio exceeds 2, and drastically falls under 5 % when it exceeds 4. This highlights the tighter economic parameters needed to secure meaningful gains under seasonal variable load demands.

4. Conclusion

This study examines whether stand-alone energy systems could benefit on hydrogen backup, given the great uncertainties surrounding future component costs and the limited deployment of fuel cells in stationary applications. Through 8000 Monte Carlo simulations across constant and seasonal load profiles, we find that hydrogen integration can improve the levelised cost of energy (LCOE), but only under narrow and often unrealistic cost conditions.

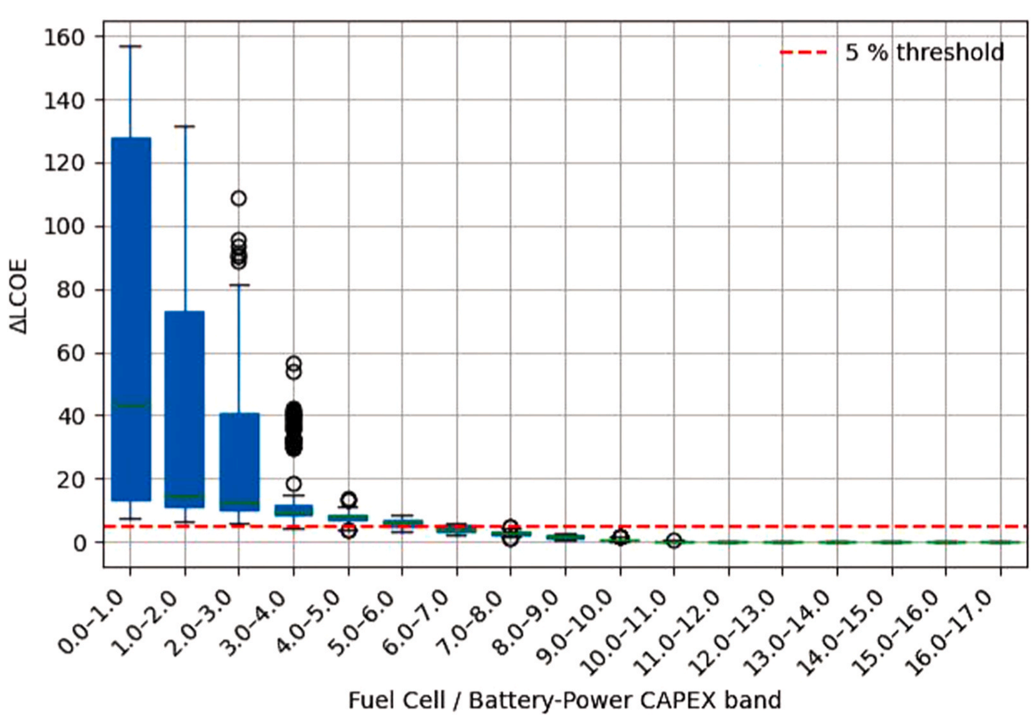


Fig. 8. Box plot illustrating how the ΔLCOE, under the seasonal load scenario, varies with fuel cell vs battery power capital cost ratios.

The use of constant and seasonal load profiles reflects their status as the most hydrogen-favourable cases identified in our earlier work, and thus they serve as upper-bound scenarios. By evaluating hydrogen under conditions most likely to highlight its advantages, we establish a clear reference point. If hydrogen fails to outperform batteries in these idealised settings, its competitiveness under more typical or variable demand conditions becomes even less plausible. This framing also clarifies that our findings are not representative of general real-world demand profiles but rather illustrate the outer limits of hydrogen's potential role under cost uncertainties.

Our results show that hybridising batteries with hydrogen becomes economically attractive only when multiple hydrogen component costs decline simultaneously. The fuel cell-to-battery power capital cost ratio emerges as the dominant factor in driving down the LCOE. For constant load profiles, median LCOE improvements remain below 12 %, with a maximum of 20 % under favourable cost conditions. Achieving more than 5 % savings requires the fuel cell to be no more than 7 times as expensive as the battery power component, a threshold that reduces to 4 under seasonal load scenarios.

Seasonal nighttime loads, despite offering a theoretical ΔLCOE range of 0–156 %, only yield substantial gains under highly optimistic and economically unrealistic conditions where battery costs remain high and fuel cell costs fall drastically to its projected 2050 values. Once battery costs drop below approximately $380/kWh, hydrogen integration consistently yields less than 20 % LCOE improvements, even under aggressive fuel cell cost reductions. In addition, under seasonal load demand, the electrolyser gains prominence due to its intensive operation during surplus generation periods, further narrowing the economic tolerances.

These findings illustrate the complexity of hydrogen integration. The lack of consensus on future hydrogen demand, and the resulting uncertainty in fuel cell cost trajectories, make it difficult to identify robust pathways for economically viable hydrogen deployment. This is especially true for stationary, stand-alone systems, where fuel cells are yet to make a breakthrough.

By comparing hybrid systems against battery-only configurations, this study sets boundary conditions for assessing hydrogen's potential contribution in stand-alone energy systems under cost uncertainty. Even in hydrogen favourable load profiles with pronounced solar seasonality, our results show that unless fuel cell costs fall at significantly faster rates than battery costs, the added complexity of integrating hydrogen is unlikely to be economically justified. These findings should be interpreted as boundary conditions. If hydrogen cannot demonstrate competitiveness under idealised scenarios, it is even less likely to do so under more moderate, real-world profiles. As such, the decision to bet on hydrogen backup should be made cautiously, with full consideration of load profile characteristics, cost interdependencies, and evolving maturity of fuel cell technologies.

CRediT authorship contribution statement

Dan Virah-Sawmy: Writing – original draft, Visualization, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Fiona J. Beck:** Supervision, Methodology, Conceptualization. **Bjorn Sturmberg:** Writing – review & editing, Supervision, Methodology, Conceptualization.

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.

Acknowledgement

This work was supported by the Reef Restoration and Adaptation Program.

The Reef Restoration and Adaptation Program is funded by the partnership between the Australian Governments Reef Trust and the Great Barrier Reef Foundation..

Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.egyr.2025.10.026.

Data availability

Data will be made available on request.

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