

Community Batteries: Technology Overview and Multi-Market Techno-Economic Assessment

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ABSTRACT

Community Batteries (CBs) are emerging as critical assets for energy communities, enabling shared access to storage, facilitating renewable integration, and enhancing grid resilience. A techno-economic framework is developed to evaluate CBs across multiple markets, combining a comparative review of battery technologies with an optimization model applied to an Australian case study. The analysis considers lithium-ion chemistries (NMC, LFP, LTO) alongside vanadium redox flow batteries, highlighting how their technical properties align with community-scale operational requirements. Results indicate that vanadium redox flow batteries, with their scalability and long lifetimes, achieve cost-effectiveness across a wide range of conditions, whereas high-power lithium-ion technologies become viable only under favorable ancillary service prices. Participation in frequency control ancillary service markets emerges as the dominant factor shaping economic outcomes, with high-power CBs capable of unlocking large annual revenues in specific contexts. Sensitivity analysis confirms that profitability is influenced far more by market and price conditions than by moderate cost variations. These findings provide actionable insights for communities, policymakers, and regulators on the design of supportive frameworks for CBs deployment.

1. Introduction

Energy communities are a growing and multifaceted phenomenon involving a range of possible activities around community-owned distributed energy resources [1]. According to the European Commission “Energy communities organise collective and citizen-driven energy actions that help pave the way for a clean energy transition while moving citizens to the fore. (...) This, in turn, helps contribute to a more decarbonized and flexible energy system” [2]. Their configurations vary widely: some focus on renewable electricity generation, others integrate heating, electric mobility, or multi-vector solutions, while governance can range from grassroots cooperatives to utility-facilitated schemes [3]. Importantly, energy communities also offer opportunities to rural residents to access electricity even in remote areas, as well as, to urban residents who may lack access to private distributed energy resources, such as renters or those living in high-rise apartments, to participate in the energy transition and benefit from local decarbonization initiatives [4].

Despite these potentialities, the operational challenges of energy

communities remain significant. The majority of energy communities are built around photovoltaic (PV) systems, which have been increasingly adopted by residential, commercial, and industrial customers alike [5]. Yet PV systems generate mismatched profiles compared to local demand and aggravate congestions in distribution networks. Storage is thus a central enabler but individual household batteries are costly, small in scale, and limited in their ability to provide system-level services. Community Batteries (CBs), by contrast, pool investment at the community level, allowing larger installations that can not only optimize local self-consumption but also participate in wholesale and ancillary service markets. Despite this promise, the economic viability of CBs remains contested, and comparative studies examining multiple battery technologies and market contexts are scarce.

Existing literature has shown that CBs operated only to reduce customers' retail costs and absorb excess PV are not always economically feasible, as the economic savings do not necessarily cover the initial investments [6]. Nevertheless, CBs still present themselves as more cost-effective solutions for the decarbonization of a community than private batteries [7–9]. Importantly, the shared investment nature of

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Nomenclature			
Variables			
$[p]_b^{[ch/dh]}$	Battery active charge/discharge power	T	Time horizon
$[p/q]_b$	Battery active/reactive power output	$\delta^{[r/l]}$	Raise/lower service duration
$p_b^{[r/l]}$	Battery raise/lower service	$[\bar{p}]_b^{[ch/dh]}$	Battery active charge/discharge power limit
soc_b	Battery state of charge (energy-based)	$[\bar{q}/\underline{q}]_b$	Battery reactive power upper/lower limit
$[p/q]_{HS}$	Host site net active/reactive power output	$[\bar{p}/\underline{p}]_b$	Battery maximum/minimum ramp rate limit
S_{HS}^{max}	Host site peak power	\bar{S}_b	Battery rated power
\bar{S}_{HS}	Host site apparent power	$[\overline{soc}/\underline{soc}]_b$	Battery state of charge upper/lower limit
YCF	Yearly cash flow	E_b	Battery capacity (energy-based)
L	Lifetime of a device	$[\eta]_b^{[ch/dh]}$	Battery charge/discharge efficiency
x_{BIC}	Break-even investment cost of a community battery – PV system	$[C]_b^{[ch/dh]}$	Battery operational cost for charge/discharge
x_{CB}	Break-even investment cost of a community battery	p_{PV}	PV power generation
Parameters		p_d	Building power demand
t	Time index	λ_{HS}^{PC}	Peak demand price
Δt	Time step	$\lambda^{[r/l]}$	Raise/lower service price
		λ^{WS}	Wholesale energy market price
		α	Binary parameter for peak demand tariff activation
		L	Lifetime of a device

CBs allows the installation of considerably larger batteries when compared to private batteries. In turn, this unlocks certain benefits that can be leveraged to achieve CB feasibility.

First, as larger assets than private batteries, CB projects can attract stakeholders that operate CB to participate in different system-level markets and services in a level-playing field [10]. In turn, the CB can accrue significant revenues, especially from frequency regulation services, for which batteries have outstanding capabilities [11–13]. Moreover, existing literature focused on residential customers, often neglecting the potential of CBs installed on a host site that is a large commercial customer. In these customers network tariffs are often comprised of peak demand component. CBs may be able to successfully reduce peak demand charges as well as participate in system-level markets, further increasing its revenues and paving the path for economic feasibility [14].

Furthermore, battery technologies beyond the widespread Lithium-ion for residential batteries may be available, and more suitable in the context of CB. In literature there is a lack of investigation on this matter and existing papers focus on optimal size, operations [15], site [16] and business model and regulatory issue [17], rather than examining which kind of battery technology is best suited to achieve an economically feasible energy community deploying CBs. A framework for sizing a generic CB used for peak demand reduction in an energy community participating in the Australian National Electricity Market (NEM) is presented in [18]. A methodology to size a CB for bill management and ancillary services provision is presented in [19], where the CB is a generic Lithium-ion Battery (LiB).

It is important to note that different battery technologies, each defined by different chemistries, present different investment costs, performances and characteristics, such as efficiency, response time, operating conditions, which will have a material impact on economic feasibility of the energy community, especially when considering services provision and value stacking. Furthermore, some technologies raise safety concerns which can be problematic, especially in inhabited areas.

Several studies have explored the cost-effectiveness of different energy storage technologies. A techno-economic evaluation of several utility-scale energy storage technologies in China energy market is presented in [20]. The analysis encompasses battery, compressed-air, pumped-hydro, hydrogen, and thermal energy storage technologies without examining specific technologies. Similarly, [21] evaluates multi-energy storage systems for microgrids, analyzing batteries,

compressed-air, and hydrogen storage technologies. Despite these contributions, existing literature does not delve into the chemistry of energy storage systems.

This paper evaluates the feasibility of different battery technologies employed as CBs. Rather than aiming at statistical representativeness of all possible community configurations, this study focuses on isolating the techno-economic mechanisms that determine the viability of different battery technologies when deployed as shared community assets. First, an overview of the main technologies is presented and the characteristic that CBs should have are stated, also considering the context in which they are operated. Some technologies are selected as suitable candidates for CB operation and their economic feasibility is evaluated. To this end, the optimal operations of CBs are evaluated. The battery is controlled in order to minimize the expenditures over a billing period, and to optimize the battery participation in energy and services markets, also considering operative restrictions for battery degradation in terms of Depth of Discharge (DoD) and number of cycles. Four different technologies of batteries are modelled and tested as CBs, as well as various scenarios with different renewable penetration, battery size, and prices condition are investigated. To this scope, appropriate battery models were developed according to their characteristics, a PV generation model from historical meteorological data was implemented, and four different years were selected based on the characteristics of their historical energy and services prices.

The outcomes of the simulations are compared on the basis of the Yearly Cash Flow (YCF) of the simulated period and on the basis of the Break-even Investment Cost (BIC) made on CB, each one with its expected lifetime, and PV panels installation, with the objective of investigating under which conditions of wholesale and services markets different technologies are economically feasible.

To this end, this work puts forward the following contributions:

- a comprehensive overview of main battery technologies outlining the essential characteristics that CBs should possess
- development of a multi-market optimization framework for CBs that explicitly integrates wholesale energy trading and contingency frequency control ancillary services, enabling a consistent assessment of value stacking under different market conditions and renewable penetration;
- application of the proposed framework to a unified techno-economic comparison of multiple battery chemistries, ensuring symmetric

modeling assumptions to isolate the role of technological characteristics and market access;

- policy highlights and suggestions to help policymakers, distribution system operators and investors taking informed decisions regarding CBs deployment.

The remaining of the paper is structured as follows. Section 2 reviews the available battery technologies in the market and explains the reasons behind the choice of such technologies as CBs. Section 3 outlines the community set-up and details the methodology to optimally control the CB. Section 4 introduces the case studies. Section 5 presents the results. Section 6 contains draws the conclusions.

2. Overview of battery technologies for local communities

The choice of battery technology is central to the economic and technical viability of CBs, since different chemistries entail different lifetimes, Energy-to-Power (E/P) ratios, safety considerations, and capital costs. These parameters directly influence which services a CB can provide and under what conditions it can be profitable. For example, high Round-Trip Efficiency (RTE) and fast response are critical for participation in ancillary services such as Frequency Control Ancillary Services (FCAS), while scalability and long lifetimes are more relevant for communities prioritizing long-duration storage and gradual decarbonization through PV integration. Safety and environmental impacts are especially important in urban deployments, where CBs are embedded in residential or commercial areas. The following review examines candidate battery technologies, with emphasis on how their technical properties align, or fail to align, with the operational requirements of community-scale storage.

In the context of local communities, a CB suitable technology must possess the following characteristics:

- safe, especially if operated in inhabited areas;
- easily scalable and controllable;
- power and capacity ratings larger than 50–100 [kW – kWh].

On the contrary, large power and energy densities are not requirements given the steady operations.

Among the wide range of battery technologies, the investigation of suitable solutions for CB application focused on commercialized and early commercialized technologies, possessing the characteristics listed above. Therefore, the research was broadly reduced to LiBs, Redox Flow Batteries (RFBs), Sodium-Sulfur (NaS), Nickel-Cadmium (NiCd), and Lead-acid batteries.

NaS batteries were discarded as this technology presents the following drawbacks:

- it needs high operating temperatures, around 350 °C, raising safety concerns [22].
- NaS battery is highly dangerous if the liquid sodium comes into contact with the water in the atmosphere.

NiCd batteries have long cycle life and are generally cost-effective [22,23], these two advantages make this technology the one with lowest cost per cycle [24]. However, these batteries present two important drawbacks:

- they have fast self-discharge rates which prevent them from being used in storage applications and make them suited for portable applications;
- their toxicity poses health risks in humans and creates disposal hazards [22].

Due to these drawbacks, also NiCd batteries were discarded.

Lead-acid batteries are commonly used in storage applications,

however they are slowly being replaced by LiBs which show higher efficiency, longer life and good performance at low State of Charge (SoC). For these reasons, also Lead-acid batteries were discarded.

LiBs are a well-established technology, with widespread adoption for the provision of different grid services, *i.e.*, peak-shaving, frequency regulation, renewable energy integration, power management [25]. LiBs provide high energy and power density, high efficiency, low self-discharge and long cycle life when compared to other traditional battery technologies. The main drawbacks of LiBs are related to investments costs and the impact of the DoD on LiBs lifetime [26].

RFBs are an emerging technology, involving different chemical species with respect to LiBs. A key difference from LiBs is that RFBs have the storage material in separated tanks, resembling an electrolyzer-fuel cells system. As shown in Fig. 1, RFB consists of two electrolyte tanks for energy storage, a cell unit for energy conversion, and pumps for circulating the electrolytes between the cell unit and the electrolyte tanks [27]. Due to the physical separation of reservoirs and cells, RFBs are scalable and present significant flexibility in the E/P ratio [26,28]. This scalability and flexibility can be leveraged to tailor the CB needs of an energy community.

For these reasons, this paper focuses on the LiBs and RFBs technologies. The following subsections delve into the details of the characteristics of the two selected groups of technologies.

2.1. Lithium-ion battery technologies

There are six types of LiBs commercially available which differs to each other according to the chemical species composing the active material in the battery, namely: Nickel-Manganese-Cobalt (NMC), Lithium-Iron-Phosphate (LFP), Lithium-Titanium-Oxide (LTO), Lithium-Cobalt-Oxide (LCO), Lithium-Manganese-Oxide (LMO), and Nickel-Cobalt-Aluminum-Oxide (NCA). Fig. 2 provides a graphic summary of the characteristics of the six types of LiBs, supporting the discussion in the following paragraphs.

NMC batteries use a compound of Lithium, Nickel, Manganese and Oxygen as the cathode material and graphite as anode material. These batteries are employed in power tools and are one of the most preferred battery chemistries for Electric Vehicles (EVs) [29], and in stationary applications, the Tesla Powerwall (TP) battery is indeed a NMC. However, Tesla could change the type of the next-generation TP from NMC to LFP [30]. LFP batteries use a compound of Lithium, Iron, Phosphorous and Oxygen as the cathode material and graphite as anode material. These batteries are suitable for high-power applications [29] and can be used in harsh conditions, making them a good option for applications in low-powered EVs, for industrial equipment that have previously relied on lead-acid batteries because of the high DoD that they can achieve [31], and mainly for stationary applications [32]. Finally, LTO batteries generally uses the NMC cathode and a compound of Lithium, Titanium and Oxygen as anode. These batteries are not commonly used in consumer electronics due to their lower energy density, but their fast charging and discharging rate make them suitable for applications in heavy machinery, power tools, and EVs [32]. Moreover, they can be employed as uninterrupted power systems and in storing wind and solar energy and creating smart grids [29].

NMC, LFP and LTO are considered as potential technologies that could be suitable in the context of CBs. NMC is selected considering the TP as a reference technology, due to its widespread adoption. LFP is also considered as it will be used in next generation of TPs, and is the technology used in the 3MWh Tesla Megapack [33] supporting its use in large scale applications. Finally, the LTOs are considered given: i) the minimal impact of low energy density in stationary applications; and ii) the potential to explore significantly lower E/P ratios in CBs, *i.e.*, as low as 0.1 [kWh/kW] [34,35], making it a very interesting technology to examine in a context of services market participation. Moreover, the presence of Titanium elevates the LTO technology investment costs [34], hindering its use in household applications.

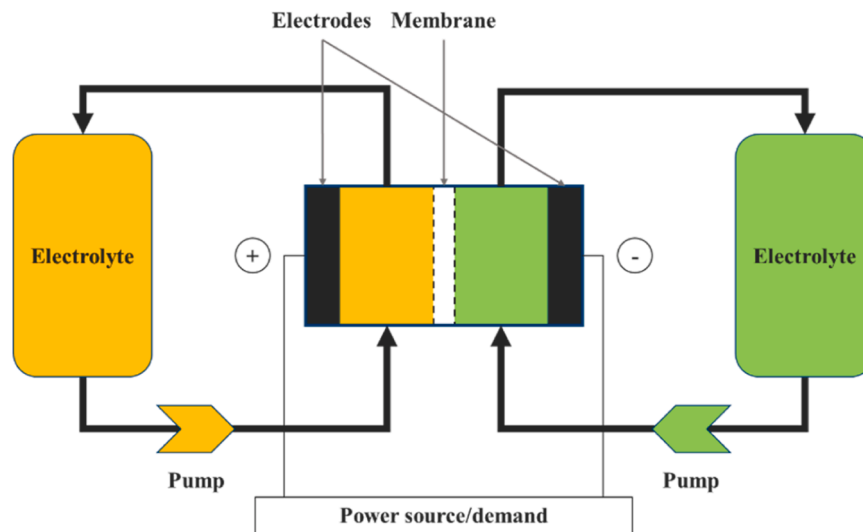


Fig. 1. Redox flow battery system.

The remaining Lithium-ion technologies i.e., NCA, LMO, and LCO are not considered adequate in the context of CBs. LCO batteries are suitable for applications in small portable electronic devices, whereas LMO batteries find use in medical, military and industrial applications requiring high continuous power, and in some EVs [29]. Finally, NCA batteries are used in EVs and grid storage applications [29], however they are less safe than the other LiBs [31].

2.2. Redox flow battery technologies

There are three major types of RFBs [36]: the traditional RFBs, the hybrid RFBs, and the slurry RFBs. A complete dissertation of the different types of RFBs is beyond the scope of this paper. This work considers the Vanadium Redox Flow Battery (VRFB), belonging to the group of the traditional RFBs. The other type of RFBs are not considered due to: low Technology Readiness Level (TRL) [37]; lack of available information in the literature or in commercially available reports (e.g., slurry all-Iron Redox Flow Battery); similar characteristics to VRFB at a higher cost (e.g., hybrid Zinc-Bromide Redox Flow Battery [34]).

Commercial VRFBs are intended for long discharge application and generally have high E/P ratio, in the range of 3–8, with 4 being the most common [38–40]. This is a relevant difference when compared to LiBs that have generally lower E/P ratio. For instance, LFPs and LTOs equipped with appropriate power conversion systems can reach E/P ratios of 0.5 and 0.1, respectively [35]. Furthermore, VRFB is also a good candidate to provide frequency regulation services [13,41]. With respect to LiBs, RFBs have usually longer lifetime, higher DoD, but lower RTE [34,35]. Finally, in [42] it is conducted a life-cycle assessment on VRFBs and LiBs for renewable energy storage applications showing that VRFBs have consistently lower environmental impact in terms of fine particulate matter formation and terrestrial acidification. In terms of equivalent carbon emission, VRFBs and LiBs have similar values [42], ranging from 100 kgCO₂/MWh of the VRFB to 50 kgCO₂/MWh of the NMC, in applications involving renewable generation support [43]

3. Energy community framework

In this section, the community set-up is first outlined, then the context in which the community operates is presented and the optimization problem is detailed. Last, the analysis of the investment made on CB and renewable generation is presented. The optimization problem is formulated as second-order cone programming to guarantee computational efficiency and accurately represent the operation of CB as inverter-interfaced resources.

3.1. Community set-up

Energy communities are typically groups that focus on promoting and implementing sustainable energy practice within a community. The set-ups of such communities can be different, renewable generation can be distributed in multiple buildings or locations, it can be centralized in one energy farm, or it can be both. The same organization also applies to energy storage systems.

In this paper, the community set-up is comprised of the CB and a host site with an energy demand, i.e., load and a PV system, located in an urban area, as presented in Fig. 3. The net imports and exports of the host site (considering the CB output, demand and PV generation) are metered at the interface of the host site with the upstream grid, for peak demand reduction and system-level market participation. The community is represented by a single host site with aggregated demand and generation. This assumption reflects practical CB deployments where storage is connected behind a single metering point and operated on behalf of multiple users. While individual community members may have heterogeneous load profiles, their aggregation preserves the key drivers relevant to battery operation, namely peak demand, net energy balance, and exposure to market prices.

3.2. Market and techno-economic assessment set-up

The proposed techno-economic framework allows to quantify the performance of various battery technologies as CBs participating in various markets and services. As the case study is located in Australia, the different markets and services considered in the proposed framework are reviewed with a special focus on the Australian context. Nevertheless, the proposed formulation can be seamlessly deployed in different jurisdictions, as mechanisms are generally equivalent in different competitive energy markets.

The Australian NEM is an active market managed by the Australian Energy Market Operator (AEMO), in which:

- the dispatch is computed every five minutes [44];
- the spot price is established based on the marginal cost of electricity, at which all dispatched generators are remunerated [45];
- the CB can use the volatility of spot prices to engage in arbitrage accruing revenues from wholesale market participation [46].

FCAS in the NEM operate on a settlement interval of five minutes. Their primary objective is to ensure that the system's frequency remains within the prescribed standards under all conditions. In Australia distributed energy resources (such as CBs) can only

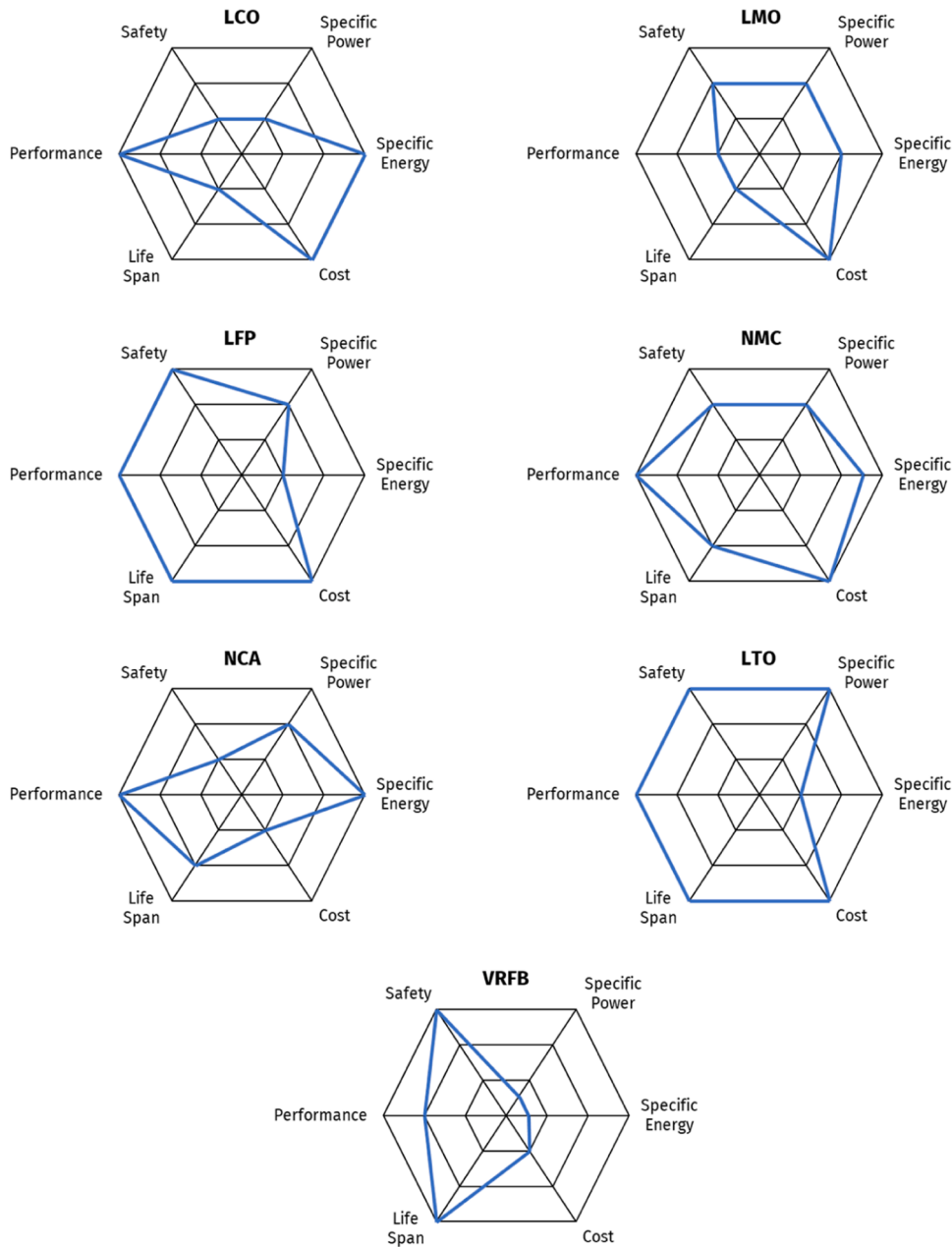


Fig. 2. Lithium-ion and Vanadium redox flow batteries characteristics.

participate in “contingency” FCAS, providing availability to change their output to manage frequency in major events, e.g., loss of large generators or load blocks. In this sense, the majority of payments the CB would perceive from contingency FCAS come from availability rather than delivery, and, conservatively, only availability payments are considered in the proposed framework. Contingency FCAS can be categorized in:

- "Raise" to rectify frequency drop events;
- "Lower" to address frequency rise events;
- further categories are established depending on response time and service duration, i.e., fast, slow, and delayed FCAS.

Finally, beyond market participation, the energy community will be subject to peak demand network tariff. Therefore, the CB is controlled for peak shaving, reducing the peak demand of the host site, which will result in economic savings.

3.3. Energy community optimal operations

To evaluate how different battery technologies can be optimally operated within this context, the problem is formulated as an optimization framework that captures energy balance, markets participation, peak shaving, and technical constraints, ensuring that results reflect realistic operational conditions.

Let subindex HS denote the host site net imports and exports, and b denote the CB operation, PV denotes the PV system generation, and D the host site demand. Additionally, $r \in \Omega_R$ denotes the set of frequency raise services whereas $l \in \Omega_L$ denotes the set of frequency lower services. The CB operational framework is formulated as a multi-period optimization problem for each time-step within the optimization horizon $t \in T$. Time-varying variables are highlighted by the inclusion of (t) whereas the subindex t denotes a time-varying parameter. Finally, in this paper, the symbol \$ is used to refer to the Australian dollars.

The objective function is presented in (1) and it is comprised of two

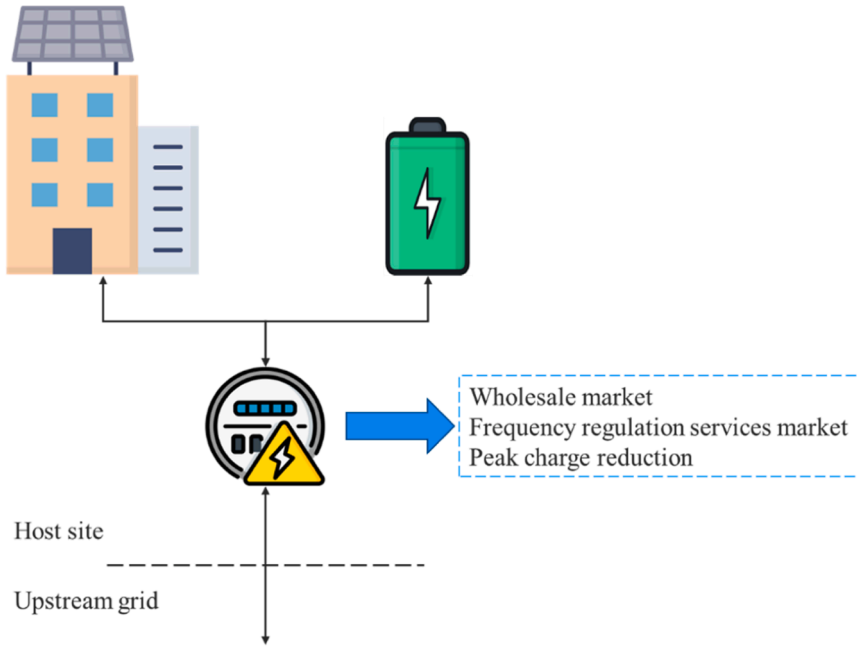


Fig. 3. System set-up. The host site has rooftop PV panels and it is equipped with a battery. The community interfaces with the upstream grid, participating in the wholesale and frequency regulation services markets and providing peak charge reduction.

terms. The first term corresponds to time-varying costs and revenues (formulated as negative costs), which are minimized for each time-step t in the optimization horizon T . CB operational costs for charge/discharge (C_b^{ch} , C_b^{dh} [\$/MWh] respectively) avoid simultaneous charging and discharging in the absence of binary variables. Variables p_b^{ch} , p_b^{dh} [MW] represent CBs charging/discharging power. The net output of the host site p_{HS} [MW] is multiplied by the wholesale energy market price λ_t^{WS} , such that when the host site is selling energy it is considered as a revenue and when the host site is buying energy it is a cost. The next two terms correspond to the revenues accrued by FCAS participation. For raise services, revenues are a function of the service price, i.e., λ_t^r [\$/MWh], and the power committed by the CBs for each raise service p_b^r [MW]. The same is replicated for frequency lower services using λ_t^l [\$/MWh] and p_b^l [MW]. Parameter Δt [h] is the time-step duration. Peak demand is charged once in the billing period and is minimized by the CB, according to the peak demand price λ_{HS}^{PC} [\$/kVA] and the variable S_{HS}^{max} [kVA] representing the peak demand at the gate meter.

$$\min \sum_{t=1}^T \left(\lambda_t^{WS} p_{HS}(t) + C_b^{dh} p_b^{dh}(t) + C_b^{ch} p_b^{ch}(t) - \sum_{r \in \Omega_R} \lambda_t^r p_b^r(t) - \sum_{l \in \Omega_L} \lambda_t^l p_b^l(t) \right) \Delta t + \lambda_{HS}^{PC} S_{HS}^{max} \quad (1)$$

CB operation is modelled in (2) – (9). In (2) the battery charge and discharge powers are defined as positive variables, limited by their maximum charge/discharge power \bar{p}_b^{ch} and \bar{p}_b^{dh} [MW]. The net active power output of the CBs is defined in (3), establishing the convention of positive discharge and negative charge. The CB reactive power output q_b [MVar] is limited by the CB reactive power limits, \underline{q}_b and \bar{q}_b [MVar] in (4). Four-quadrant operation of CB, limited by their rated power \bar{S}_b , is established in (5). Constraint (6) sets the upper \bar{soc}_b and lower \underline{soc}_b bounds of the CB SoC soc_b [p.u.], to be intended as an energy-based state variable. The energy balance of the CB is modelled in (7), where E_b is the CB nameplate capacity [MWh]. Finally, (8) – (9) governs the ramp rates of the CB according to its minimum and maximum ramp rates $\underline{\rho}_b$ and $\bar{\rho}_b$ [MW/h], and (10) limits the energy throughput of the battery, which corresponds to limiting the number of cycles the CB can do to one per

day on average. For all $t \in [1, T]$:

$$0 \leq p_b^{[ch/dh]}(t) \leq \bar{p}_b^{[ch/dh]} \quad (2)$$

$$p_b(t) = p_b^{dh}(t) - p_b^{ch}(t) \quad (3)$$

$$\underline{q}_b \leq q_b(t) \leq \bar{q}_b \quad (4)$$

$$p_b(t)^2 + q_b(t)^2 \leq \bar{S}_b^2 \quad (5)$$

$$\underline{soc}_b \leq soc_b(t) \leq \bar{soc}_b \quad (6)$$

$$E_b (soc_b(t+1) - soc_b(t)) = \left(\eta_b^{ch} p_b^{ch}(t) - \frac{p_b^{dh}(t)}{\eta_b^{dh}} \right) \Delta t \quad (7)$$

$$\underline{\rho}_b \Delta t \leq p_b^{dh}(t) - p_b^{dh}(t-1) \leq \bar{\rho}_b \Delta t \quad (8)$$

$$\underline{\rho}_b \Delta t \leq p_b^{ch}(t) - p_b^{ch}(t-1) \leq \bar{\rho}_b \Delta t \quad (9)$$

$$\sum_{t=1}^T (p_b^{dh}(t)) \leq E_b (\bar{x}_b - x_b) \frac{T}{24} \quad (10)$$

The constraints in (11) – (16) are adopted from [47] to ensure that the CB can deliver FCAS. The raise and lower services are modelled in (11) – (12), limited by the CB ramp rate limits and the response time for the raise/lower service (τ^r and τ^l [h], respectively). The participation in the different services is limited by the CB maximum charge/discharge powers in (13) – (14). Additionally, (15) – (16) ensure there is sufficient headroom/footroom to provide the raise/lower service for the duration of the service (δ^r and δ^l [h]). For all $t \in [1, T]$:

$$0 \leq p_b^r(t) \leq \bar{p}_b \tau^r \quad (11)$$

$$0 \leq p_b^l(t) \leq -\underline{\rho}_b \tau^l \quad (12)$$

$$-\bar{p}_b^{ch} \leq p_b(t) + p_b^r(t) \leq \bar{p}_b^{dh} \quad (13)$$

$$-\bar{p}_b^{ch} \leq p_b(t) - p_b^l(t) \leq \bar{p}_b^{dh} \quad (14)$$

$$E_b \left(\text{soc}_b(t) - \underline{\text{soc}}_b \right) \geq \sum_{r \in \Omega_r} \frac{1}{\eta_b^{\text{ch}}} (p_b(t) + p_b^r(t)) \delta^r \quad (15)$$

$$E_b (\overline{\text{soc}}_b - \text{soc}_b(t)) \geq \sum_{l \in \Omega_l} \eta_b^{\text{ch}} (p_b(t) - p_b^l(t)) \delta^l \quad (16)$$

The host site operation is governed by (17) – (22). The PV output p_{PV} and the building demand p_d (all in [MW]), are defined as positive variables in (17). The host site net active and reactive power output is modelled in (18) – (19), considering the CB output is netted with the host site. It must be noted that it is assumed that the PV system does not provide reactive power support. The apparent power of the host site \bar{S}_{HS} [MVA] is modelled by (20). The peak demand S_{HS}^{max} is modeled by (21), where α_t is a time-varying parameter equal to 1 when the peak demand tariff is active, and equal to 0 otherwise. The peak demand S_{HS}^{max} and the \bar{S}_{HS} are enforced to be positive by (22). For all $t \in [1, T]$:

$$p_{PV}(t) \geq 0, \quad p_d(t) \geq 0 \quad (17)$$

$$p_{HS}(t) = p_b(t) + p_{PV}(t) - p_d(t) \quad (18)$$

$$q_{HS}(t) = q_b(t) + q_d(t) \quad (19)$$

$$p_{HS}(t)^2 + q_{HS}(t)^2 \leq (\bar{S}_{HS})^2 \quad (20)$$

$$\alpha_t S_{HS}^{\text{max}} \geq \alpha_t \bar{S}_{HS} \quad (21)$$

$$\bar{S}_{HS} \geq 0, \quad S_{HS}^{\text{max}} \geq 0 \quad (22)$$

3.4. Analysis of the investment

The results from (1) are used to analyze the profitability of the investment that has been made on the CB and PV systems, in terms of BIC.

When the billing period is one whole year, (1) returns the YCF, if positive is an incoming flow. Let us indicate with YCF_0 [\$/year] and YCF [\$/year] the YCFs obtained by solving (1) over a billing period of one year in the case no CB and no PV panels are installed and in the case a certain investment is made on these technologies, respectively, and with L [year] the lifetime of the system CB-PV panels. Then, the BIC of the system CB-PV panels, x_{BIC} [\$], can be computed from:

$$x_{BIC} = (YCF - YCF_0) \cdot L \quad (23)$$

Eq. (23) links the BIC of a system x_{BIC} with the difference between the cash flow received with the system installed and without the system installed, over the system lifetime L . Investments higher than x_{BIC} are not profitable due to low YCF and/or low system lifetime. The lifetime of PV panels is in the range of 25 – 35 years [48,49] and is longer than the lifetime of batteries. In this study the PV panels lifetime was set to 25 years and used to compute x_{BIC} from (23) when no CB is installed. A cost of 1300 \$/kW [50] was taken as reference to evaluate the profitability of the investment made on further PV generation.

When a CB battery is installed its lifetime is taken as the lifetime of the system and used to compute x_{BIC} from (23). To evaluate the investment made on the battery, the BIC of the CB, x_{CB} [\$/kWh], is computed as it follows and compared to the installation cost of such battery technology.

$$x_{CB} = \frac{x_{BIC} - 1300 \cdot \widehat{PV}_{\text{installed}}}{E_b} \quad (24)$$

In (24), 1300 [\$/kW] is the PV installation cost, $\widehat{PV}_{\text{installed}}$ [kW] is the installed PV generation, and E_b [kWh] is the battery size.

4. Case study

This section presents the case study to analyze the performance of various battery technologies as CB participating in multiple markets.

The CB is supposed to be installed at a host site consisting of a large commercial building located in Victoria (Australia) equipped with a PV system. The host site net demand and PV generation are extracted from a smart meter. The CB can participate in the wholesale and services Australian markets and to investigate the effect of market participation the same operations are repeated for the case of only wholesale market participation and for the case of wholesale and services markets participation. To this end, historical market data from four different year were extracted.

Moreover, in order to examine the CB operations at various PV penetration levels, several scenarios at different PV system size were developed by building a simple model of PV generation from historical meteorological data from the host site location.

The four selected battery technologies discussed in Section 2 were tested as CBs, each of them at four different sizes, and the results compared to the case in which no CB is installed.

The following sections details the features characterizing the case study and various scenarios.

4.1. Host site data

A large commercial building located in a city in Victoria, Australia is selected for the analysis, modelled using one year of historical smart meter data with 15-minute granularity. The peak demand of this building is 120 kW, with annual net energy consumption equal to 349 MWh. Additionally, the host site has 85 kW PV system already installed.

4.2. Market data

Historical market data in Victoria, Australia from 2010 to 2022 obtained with NEOexpress [51] displays distinct market conditions. Three parameters that might affect the economic feasibility of the CB were identified: (i) annual average wholesale market price; (ii) annual wholesale market price volatility measured as the standard deviation of the prices throughout the year; and (iii) annual average contingency FCAS prices. Therefore, four distinct years are selected, as presented in Table 1, to analyze the techno-economic operation of the CB under different market conditions.

Peak demand charges are also taken into account, based on the network tariff for large business customers found in a Victorian distribution system operator pricing proposal [52]. These charges are determined by the 12-month rolling peak demand, *i.e.*, the highest recorded demand of the customer in the last 12 months. The rate is set at 145.44 [\$/kVA year]. It must be noted that according to [52], peak demand charges apply only to peak demand between 10:00 and 18:00.

4.3. PV penetration

The current PV system installed in the host site does not allow to achieve community low-carbon objectives, as the demand throughout the year significantly exceeds the available PV generation. In fact, the PV generation excess is only 0.42% of the host site demand throughout the year of simulation.

It is therefore relevant to understand how various battery technologies perform as the community progresses in its low-carbon objectives, by increasing the installed PV capacity in the host site. To this end, a

Table 1
Historical market data.

Year	Wholesale energy market		Contingency FCAS
	Annual Average [\$/]	Volatility [\$/]	Annual Average [\$/]
2010	34.44	298.58	0.52
2011	29.37	131.74	0.72
2017	92.22	56.26	4.51
2019	109.36	433.62	2.85

simple model based on historical meteorological data was implemented to simulate the increase of PV generation. The meteorological data were collected from the database Solcast [53] from the 28th of March 2021 to the 28th of March 2022 at the exact location of the host site.

The implemented model was taken from [54] and it is detailed below. Eq. (25) sets the photovoltaic generation p_{PV} [MW] of the PV plant, which depends on the solar irradiance received by the panels G [W/m²], on the rated power of the PV plant \bar{p}_{PV} [MW], on the ambient temperature T_a [°C], and on the temperature coefficient [°C⁻¹] that has been set equal to 0.05. Eq. (26) defines the solar irradiance received by the panels, depending on the Direct Normal Irradiance G_{sun} [W/m²] and on the cosine of the angle θ . Finally, equation defines (27) the cosine of the angle θ as function of the zenith angle θ_z , tilt angle β , solar azimuth angle γ_s and panel azimuth angle γ .

$$p_{PV} = \frac{G}{10^6 [W/m^2]} \bar{p}_{PV} (1 + (T_a - 25)\beta) \quad (25)$$

$$G = G_{sun} \cos(\theta) \quad (26)$$

$$\cos(\theta) = \cos(\theta_z) \cos(\beta) + \sin(\theta_z) \sin(\beta) \cos(\gamma_s - \gamma) \quad (27)$$

Different levels of additional PV installed capacity were considered in the case study, as well as the base case, *i.e.*, original installed PV capacity. In particular the increased rated capacity of the PV plant was set to: 0, 20, 40, 60, 80, and 100 kW. The obtained PV generation p_{PV} was then summed to the original PV generation. Table 2 lists the considered additional installed PV capacity and the corresponding percentage of PV export over the net demand at the host site. The PV system cost is computed on the amount of installed additional PV generation.

4.4. Test cases: battery energy storage technologies

Different technologies at various battery capacity were tested as possible CB in order to spot the best solution. TP, *i.e.*, NMC, battery was taken as the reference technology [55] and compared with LFP battery, LTO battery, and VRFB. The specifications of the LFP battery, of the LTO battery and of the VRFB were taken from the IRENA reports [34,35,56]. All the tested batteries have very fast response time and are suitable for all kinds of FCAS provision. In all the simulations performed and for all the batteries considered, the number of charge-discharge cycles has been limited to 1 per day on average. Limiting the number of cycles is necessary in order to compare the life of the batteries on a temporal basis; in fact, without such a limit, optimization would result in several charge-discharge cycles per day, making it difficult to quantify the possible battery lifespan. Furthermore, since the ultimate goal of CBs is to facilitate the decarbonization of the electric grid, imposing the limit of 1 charge-discharge cycle per day is ideal for coupling storage with PV panels. In fact, PV generation is ideally cyclical throughout the day. The cycle limit of 1 full equivalent cycle per day also allows a consistent translation of cycle life into lifetime across technologies. Without this constraint, optimization would favor excessive short-term cycling, obscuring lifetime comparisons and leading to unrealistic degradation patterns. Moreover, in every simulation all batteries are initialized with 50% SoC. This assumption provides a neutral starting point for the battery operation within the optimization horizon. Instead, the final SoC is not specified. This assumption enables the battery to be managed

Table 2
Percentage of PV export over the net demand at the host site.

Host site additional PV generation	PV export over net demand
0 kW	0.42%
20 kW	1.22%
40 kW	3.05%
60 kW	5.99%
80 kW	10.03%
100 kW	15.18%

freely inside the upper and lower bounds throughout the whole optimization. because the optimization runs over a one-year period. Given that the optimization runs over a one-year period, the final SoC value does not influence the YCF and, consequently, does not impact the overall techno-economic assessment of the CB operation.

Table 3 shows the characteristics of the various technologies under study: E/P ratio, defined as the battery nominal power over battery capacity [kWh/kW], RTE, DoD and expected lifetime at the suggested DoD. Each of the CB was tested at four different capacity, in particular 50, 100, 150 and 200 kWh for NMC, LFP and LTO batteries, and 100, 200, 300 and 400 kWh for VRFB. As a base case, the case with no energy storage was run.

The shared nature of CBs allows to increase the asset size with respect to household batteries. In turn, this unlocks the possibility to install different battery technologies that are not feasible at the usual capacities in private-level investments, *i.e.*, 5 kW/13.5 kWh battery. As the main purpose of this paper is to understand the most attractive technologies in the context of CBs, the following test cases, for different technologies, are defined:

- **Case-I (Base Case):** no battery energy storage system installed in the host site. It will be explored the outcome of installing further PV generation at the host site to decarbonize the grid, and compared to the current situation at the host.
- **Case-II (NMC):** TP, *i.e.*, a NMC battery, is installed as CB and its integration with additional PV generation is investigated. Four different capacities are investigated at every level of additional PV installed. The results are compared to those of Case-I.
- **Case-III (Comparison with other technologies):** the other three selected battery technologies are used as CB. Similarly to the previous case, four different capacities are considered for each batteries and for each level additional PV generation. The results are compared to those of the Case-I and Case-II.

Regarding the installation cost of TP battery, it was found that in Victoria is around 1148 \$/kWh [57]. For LFP, LTO, and VRFB, however, precise installation costs were not found. According to [35] in 2020 the cost of NMC, LFP, LTO, and VRFB are 339, 466, 880, and 268 USD/kWh respectively, which account for 493, 678, 1281, and 390 \$/kWh at the exchange rate of the 16th of June 2023. A cost of 493 \$/kWh is less than a half of the TP installation cost. Since the cost of a battery storage system strongly depends on the power installation cost, taxes, install labor and equipment, permitting, inspection, interconnection and sales [58], giving a precise estimate of the installation costs of LFP, LTO, and VRFB systems, possibly in Victoria too, is hard to do.

In [34] good estimates of LFP, LTO and VRFB useful lives are given and these values are used to compute the BICs of these technologies, applying (23) and (24). A method to estimate the CB installation cost, even for these battery technologies, was implemented in order to discuss the profitability of the investment. In [59] a method to compute the installation costs of several LiB systems is presented, however the

Table 3
Battery technologies characteristics.

Community battery	NMC battery	LFP battery	LTO battery	Vanadium redox flow battery
Energy-to-power ratio	2 h	0.5 h	0.1 h	4 h
Round trip efficiency	90%	92%	96%	70%
Depth of discharge	$\bar{x}_b = 0.1$ [p.u.]	$\bar{x}_b = 0.1$ [p.u.]	$\bar{x}_b = 0.05$ [p.u.]	$\bar{x}_b = 0$ [p.u.]
Expected lifetime	$\bar{x}_b = 1$ [p.u.]	$\bar{x}_b = 1$ [p.u.]	$\bar{x}_b = 1$ [p.u.]	$\bar{x}_b = 1$ [p.u.]
Expected lifetime	10 years	10 years	23 years	19 years

method do not distinguish between different types of LiBs. In particular, the considered systems are 600 kW/2400 kWh, 600 kW/1200 kWh, 600 kW/600 kWh, and 600 kW/300 kWh, which presents the same E/P ratio of the LFP battery. To estimate the battery price [USD/kWh] for a system with an E/P ratio of 0.1, such as the LTO battery, an exponential regression was done, returning a R2 factor of 0.9872 and a battery price of 287.84 USD/kWh. Once this price was computed, the method in [59] could be applied and the results are shown in Table 4, which shows the installation cost of the considered battery. The exchange rate of the 16th June 2023 was used to switch from USD to \$.

In [60] the installed cost for a 100 kW/400 kWh VRFB system is estimated to be 617.3 USD/kWh, which are approximately 900 \$/kWh at the exchange rate of the 16th of June 2023.

5. Results and discussion

This section presents the result and discussions of the various battery technologies in the context of CB. Positive values of YCF represent an incoming flow, *i.e.*, revenues, whereas negative values of YCF represent an outgoing flow, *i.e.*, costs. Table 5 resumes the investigated test cases that will be discussed in details in the following subsections.

5.1. Scope and modeling assumptions

The analysis presented in this paper adopts a set of modeling assumptions aimed at enabling a transparent and consistent comparison of battery technologies within a CB framework. Accordingly, the results should be interpreted in light of these assumptions, which are chosen to preserve tractability, comparability, and reproducibility.

Perfect foresight of market prices is assumed to isolate the interaction between technology characteristics and market design. Under this assumption, the results identify the best achievable performance of a given CB–PV system if already installed, and the optimization provides an upper bound on its economic and operational

With respect to ancillary services, the framework considers provision of contingency FCAS through availability-based remuneration, in line with current Australian market rules for distributed energy resources. In this sense, the majority of payments the CB would perceive from contingency FCAS come from availability rather than delivery, and, conservatively, only availability payments are considered in the proposed framework, as anticipated in Section 3.3.

Battery degradation is represented through technology-specific lifetime and DoD constraints derived from established literature. More detailed degradation dynamics are intentionally excluded to avoid introducing strong nonlinearities into the optimization problem and highly uncertain and technology-dependent parameters that would hinder both optimal solution convergence and comparability across battery chemistries.

Finally, the use of a single commercial host site represents a modeling assumption. While individual community members may exhibit heterogeneous load profiles, their aggregation preserves the key

Table 4
Battery energy storage system installation cost.

Battery technology	Battery energy storage system cost [\$/kWh]
NMC battery	1148
LFP battery	
400 kW/200 kWh	3839
300 kW/150 kWh	4508
200 kW/100 kWh	5848
100 kW/50 kWh	9867
LTO battery	
2000 kW/200 kWh	9554
1500 kW/150 kWh	10224
1000 kW/100 kWh	11564
500 kW/50 kWh	15582
Vanadium redox flow battery	900

Table 5

Overview of investigated test cases for energy prices, accessed energy markets, PV integration, and community battery.

Test case	Energy prices (years) & accessed markets	Investigated PV generation	Investigated batteries (type and size [kWh / kW])
Case I	All years in Table 1 & NEM	All sizes in Table 2	None
Case II	All years in Table 1 & NEM / NEM&FCAS	All sizes in Table 2	NMC battery <ul style="list-style-type: none"> • 50 / 25 • 100 / 50 • 150 / 75 • 200 / 100
Case III	All years in Table 1 & NEM / NEM&FCAS	All sizes in Table 2	LFP battery <ul style="list-style-type: none"> • 50 / 25 • 100 / 50 • 150 / 75 • 200 / 100 LTO battery <ul style="list-style-type: none"> • 50 / 50 • 100 / 100 • 150 / 150 • 200 / 200 VRFB <ul style="list-style-type: none"> • 100 / 25 • 200 / 50 • 300 / 75 • 400 / 100

drivers relevant to battery operation, namely peak demand, net energy balance, and exposure to market prices, which are the primary determinants of CB performance within the proposed framework.

5.2. Case I – Base case

The base case considers incremental PV installations without a CB. Increasing PV capacity from + 0 to + 100 kW steadily raises net exports (Table 2) and YCF (Fig. 4), as imported energy is displaced and part of the surplus is sold to the grid.

Differences between years are driven by average wholesale price levels rather than volatility. In the absence of storage, no arbitrage can be exploited, and outcomes depend mainly on the balance between avoided imports and the value of exports. The year 2011, which displayed the lowest average wholesale prices, yields the highest YCF, followed by 2010, 2017, and 2019. Lower import costs dominate in low-price years, while higher export revenues in high-price years do not fully compensate for increased import expenses.

Investment viability is assessed through the BIC of the additional PV, displayed in Fig. 5 and defined in (23) by x_{BIC} considering a 25-year lifetime. BIC values generally exceed the reference PV CAPEX of 1300 \$/kW [50], with the exception of 2011. Additional PV investments are therefore financially viable in most price environments, though the incremental value declines as capacity increases. Larger PV additions yield lower BICs, while lower wholesale prices further depress them. Thus, PV-only expansion exhibits diminishing marginal economic benefits, even if it enhances local decarbonization objectives.

The results highlights the fundamental implication that PV-only operation is mainly influenced by average wholesale prices, while price volatility remains largely irrelevant. The declining marginal value of additional PV capacity indicates the necessity of complementary flexibility options, like CBs.

5.3. Case II – NMC battery

The inclusion of a community NMC battery substantially modifies the financial outcomes compared to the PV-only Case I – Base Case by enabling wholesale market arbitrage and participation in contingency FCAS. As illustrated in Fig. 6, scenarios without storage consistently exhibit lower (more negative) YCFs, confirming that the CB provides a measurable improvement in economic balance, even if profitability is not achieved in all cases.

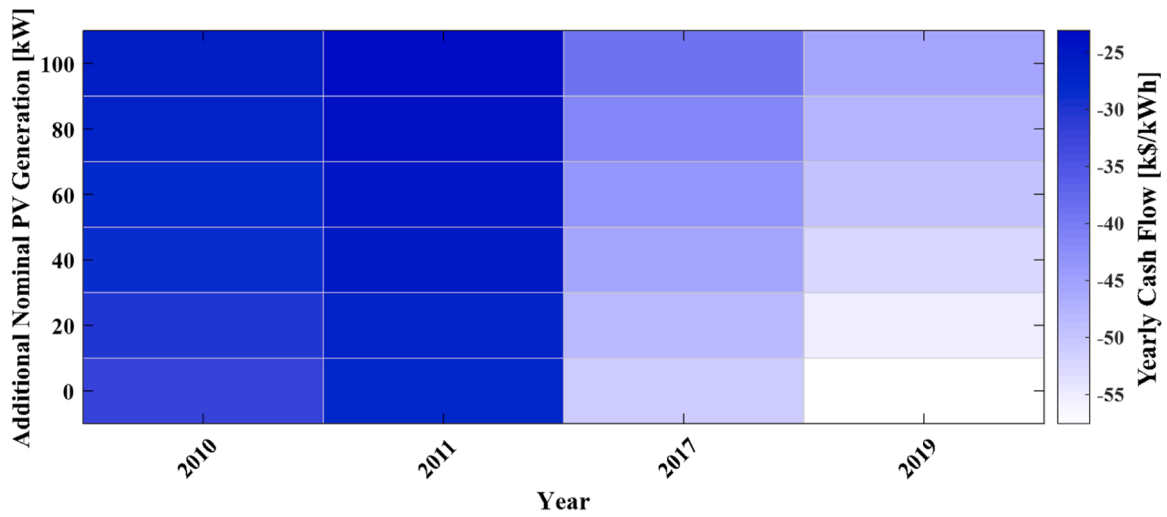


Fig. 4. Yearly cash flow in the case without any installed community batteries.

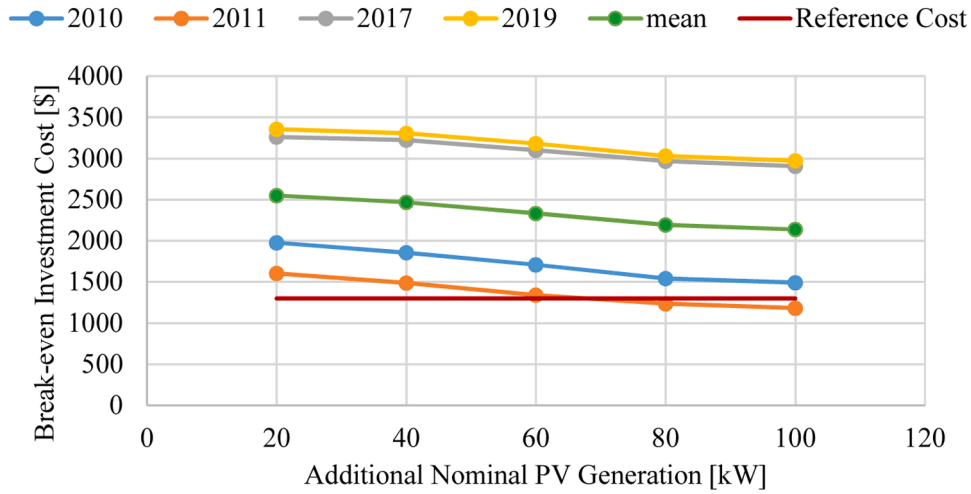


Fig. 5. Break-even investment cost of PV system installation. The reference cost is set to 1300 \$/kW and the lifetime to 25 years.

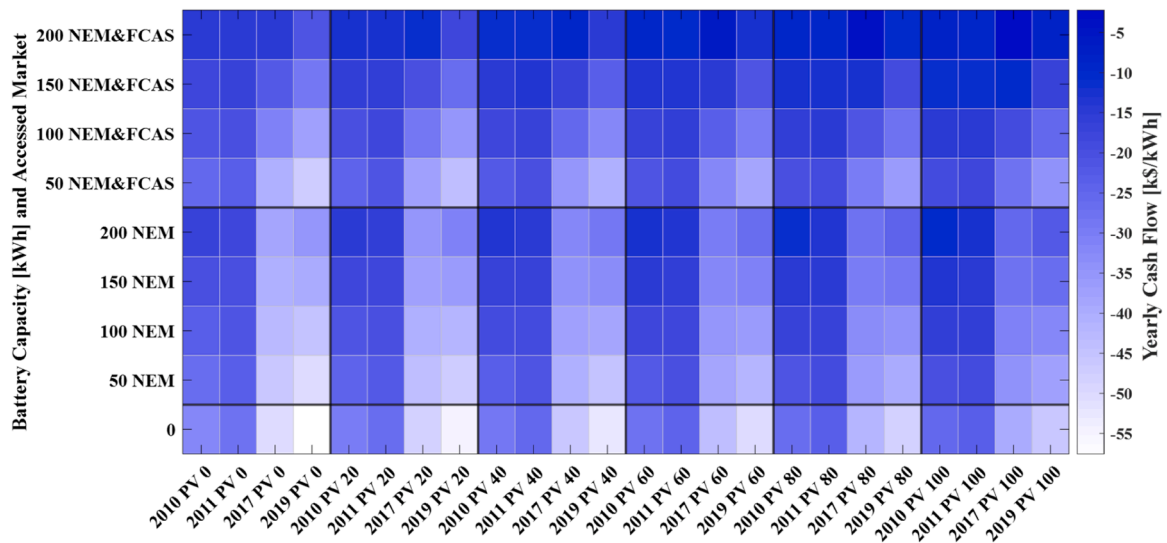


Fig. 6. Yearly cash flow with a community NMC battery operating in the NEM and FCAS market. On the y-axis, the number refers to the battery capacity [kWh] and the acronym refers to the accessed markets. On the x-axis, the year and the additional nominal PV generation [kW] are displayed.

Two main trends characterize the results. First, YCF increases with higher PV penetration at every battery size, reflecting the greater availability of surplus generation for storage and arbitrage. Second, YCFs improve with larger battery capacities across all PV levels, as greater flexibility enables more effective capture of market opportunities. These effects are visible under both wholesale-only (indicated with “NEM” in all coming figures) and wholesale–FCAS (indicated by “NEM&FCAS” in all coming figures) participation.

The role of wholesale market conditions is also evident. Under wholesale-only operation, years with lower average prices (2010 and 2011) yield higher YCFs than years with higher prices (2017 and 2019). This outcome reflects the fact that in low-price environments, avoided import costs outweigh the limited value of exports. Volatility exerts an even stronger influence. Between 2010 and 2011, the year with higher volatility (2010) produces larger YCFs despite its higher mean prices. A comparable effect emerges in the comparison between 2019 and 2017, underscoring that arbitrage value depends primarily on temporal price variability rather than average levels.

When FCAS revenues are included, YCFs improve substantially across all battery and PV sizes. Availability payments provide an additional income stream that partially compensates for the high capital costs of storage, especially in years with elevated FCAS prices. The ranking of years shifts accordingly: while 2010 and 2011 dominate in wholesale-only scenarios, years 2017 and 2019, which are characterized by high FCAS prices, achieve the highest YCFs under combined market participation. This reversal highlights the decisive role of ancillary service prices in shaping profitability, particularly at larger battery capacities where higher nominal power allows greater FCAS commitment.

As described in Section 4.4 the considered NMC battery in this case is the TP battery. TP battery [55] is a 7 kW/13.5 kWh battery and has a cost of around 15,000–16,000 \$ [57], returning a storage cost of around 1148 \$/kWh. This battery is a NMC LiB and it has a warranty of 10 years ensuring at least a State of Health (SoH) of 70% with a DoD of 100%. In the simulations the DoD of the NMC battery was limited to 90%, as stated in Table 3 and suggested in [34]. This limitation on the DoD, together with the limitation of 1 cycle per day, would extend battery lifetime, possibly ensuring 80% of SoH after 10 years. The effect of limiting the DoD is reducing the net capacity of the battery by a percentage factor equal to (100-DoD)%. BICs derived from Eqs. (23) and (24) are reported in Fig. 7 where x_{CB} lower than 1148 \$/kWh is marked as red cells. Profitable investments are observed only in favorable price conditions. Under wholesale-only participation, the combination of high

average prices and volatility in 2019 allows cost recovery up to 150 kWh of installed capacity, while the 200 kWh case is feasible only with moderate PV additions (20–80 kW). The inclusion of FCAS significantly expands the range of profitable configurations. Years 2017 and 2019 consistently deliver BICs above the reference cost, indicating robust investment viability, while 2010 and especially 2011 remain less favorable due to low FCAS prices.

An additional pattern emerges when comparing different scales of investment. Smaller batteries tend to achieve higher BICs, since their lower capital requirements are more easily offset by revenues. This suggests that cautious, small-scale investments are more likely to return profits, although larger capacities yield higher absolute YCFs when conditions are favorable.

These results underscore two structural insights. First, arbitrage value is driven by volatility rather than by average wholesale price levels. Second, FCAS revenues are pivotal in determining investment feasibility, with high ancillary service prices enabling profitability even at larger capacities. CBs based on NMC technology therefore remain highly dependent on market design, particularly on access to and remuneration from ancillary services.

5.4. Case III- comparison with other technologies

As presented in Section 4.4, other batteries were tested as CBs to evaluate the impact of the E/P ratio, DoD, and RTE. Several types of LiBs are compared to each other, namely LFP, LTO, and NMC (the TP battery) and to a VRFB. LiBs have generally lower E/P ratio, specifically, LFPs and LTOs equipped with appropriate power conversion systems can reach E/P ratios of 0.5 and 0.1, respectively [35]. As discussed in Section 3.4, the BICs of the CBs were used as the parameters over which address the profitability of the investment. The computation of such parameters, through (23) and (24), requires the knowledge of the CBs lifetime. In [35], the full equivalent cycles to reach the end of life is estimated to be 3500 for LFP and 10,000 for LTO and VRFB. However, the maximum equivalent number of cycles for these technologies are expected to increase by 2030 [34] and some producers already claim that their battery can last longer [40,61]. Taking as reference the data in [35], and having limited the number of cycles to maximum 1 full cycle per day, the amount of years that LFP, LTO and VRFB are expected to last are 10, 23 and 19, respectively (Table 3).

The same operations that have been run with the NMC battery have also been conducted with the LFP, LTO and VRFB technologies working

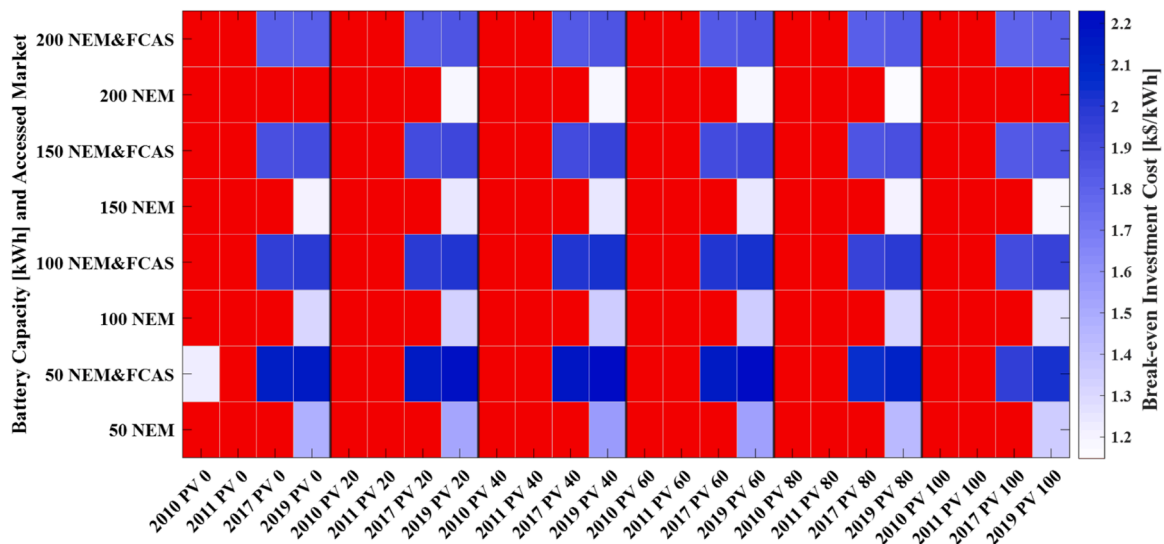


Fig. 7. Break-even investment costs for community NMC battery-PV system. On the y-axis, the number refers to the battery capacity [kWh] and the acronym refers to the accessed markets. On the x-axis, the year and the additional nominal PV generation [kW] are displayed. Red cells indicate unprofitable investments.

as CBs. LFP and LTO batteries were tested at the same capacities of NMC batteries, while VRFBs were tested at 100, 200, 3000, and 400 kWh. The comparison across LFP, LTO, and VRFB technologies highlights how differences in E/P ratio, RTE, DoD range, and lifetime shape the techno-economic feasibility of CBs. Fig. 8 shows the YCF when the CBs operate in the NEM, while the YCFs when CBs participate also in the FCAS market are shown in Fig. 9, while Figs. 10–12 display the corresponding BICs.

For all technologies, YCFs improve with higher PV penetration and are consistently enhanced by participation in FCAS markets. In wholesale-only operation, none of the chemistries achieves positive YCFs, regardless of capacity or PV level. Years 2010 and 2011, characterized by lower average wholesale prices, deliver the highest YCFs, with volatility amplifying arbitrage revenues. However, the magnitude of YCF gains remains insufficient to offset investment costs.

The decisive effect of FCAS participation is visible across all chemistries. Under the high ancillary service prices of 2017 and 2019, YCFs increase substantially, in some cases turning positive. This effect is most pronounced for high-power chemistries with low E/P ratios, such as LTO, where FCAS availability payments dominate total revenues. By contrast, for VRFB, characterized by a high E/P ratio, wholesale price volatility remains an equally important determinant of YCF outcomes.

The profitability assessment based on BIC provides clearer differentiation among technologies. For both LFP and LTO, investments remain unprofitable in wholesale-only operation, regardless of size or PV level. Only under favorable FCAS conditions (2017 and 2019) BICs exceed reference costs, and even then, only for selected configurations. By contrast, VRFBs exhibit significantly stronger performance: profitable outcomes are observed not only under high-FCAS years but also under conditions of strong wholesale price volatility (e.g., 2010), even without ancillary service revenues. This resilience reflects the VRFB high E/P ratio and long lifetime, which enable effective use of volatility-driven arbitrage opportunities over extended periods.

Overall, the results confirm that while all technologies benefit from FCAS, the degree of dependency differs: LFP and LTO require favorable FCAS markets to approach profitability, whereas VRFBs are less exposed to ancillary price swings and can achieve cost recovery under a wider set of conditions.

Specifically, for LFP batteries, this technology offer good efficiency and wide DoD range, but profitability remains tied to high ancillary service prices. Under 2017 conditions, medium-to-large LFP configurations achieve BICs above installation cost, but in lower-price FCAS situations investments remain unprofitable. LFP therefore represents a potentially viable but market-dependent option, suitable in contexts where ancillary service revenues are expected to be stable and significant.

LTO batteries provide outstanding cycle life and fast response, which aligns well with FCAS requirements. However, high capital costs limit profitability, making favorable FCAS prices a prerequisite, despite the largest RTE and expected lifetime and wide DoD range. Even under strong FCAS conditions, only selected configurations reach attractive BICs, and wholesale-only operation is never viable. LTO CBs value proposition is therefore highly conditional, and its adoption at community level is justifiable only if rapid-response capability is explicitly rewarded through market design or policy incentives.

Finally, VRFBs consistently emerges as the most resilient option. The technology ability to decouple power and energy ratings, long lifetime, and competitive costs allow profitability in a broader range of scenarios, despite the smaller RTE. Unlike Lithium-ion chemistries, VRFBs can achieve viable BICs even in most wholesale-only contexts with strong volatility. Participation in FCAS market further enhances returns but is not strictly necessary for viability. This robustness positions VRFB as the most suitable technology for communities seeking long-term, low-risk investments, especially in policy environments that value durability and safety. Lastly, the ability of decoupling power and energy ratings makes the VRFB an agile investment whose energy and power capabilities can be adjusted according to markets evolution trends.

5.5. Sensitivity analysis on CAPEX

The sensitivity analysis explores the impact of variations in battery capital expenditure on the financial outcomes of CB projects. Investment costs were perturbed by $\pm 5\%$, $\pm 10\%$, $\pm 20\%$, $\pm 30\%$, $\pm 40\%$, and $\pm 50\%$, relative to the reference values used in the main simulations (see [Supplementary Material](#), Figures SM1–SM48).

The results indicate that changes in capital cost shift BIC in the

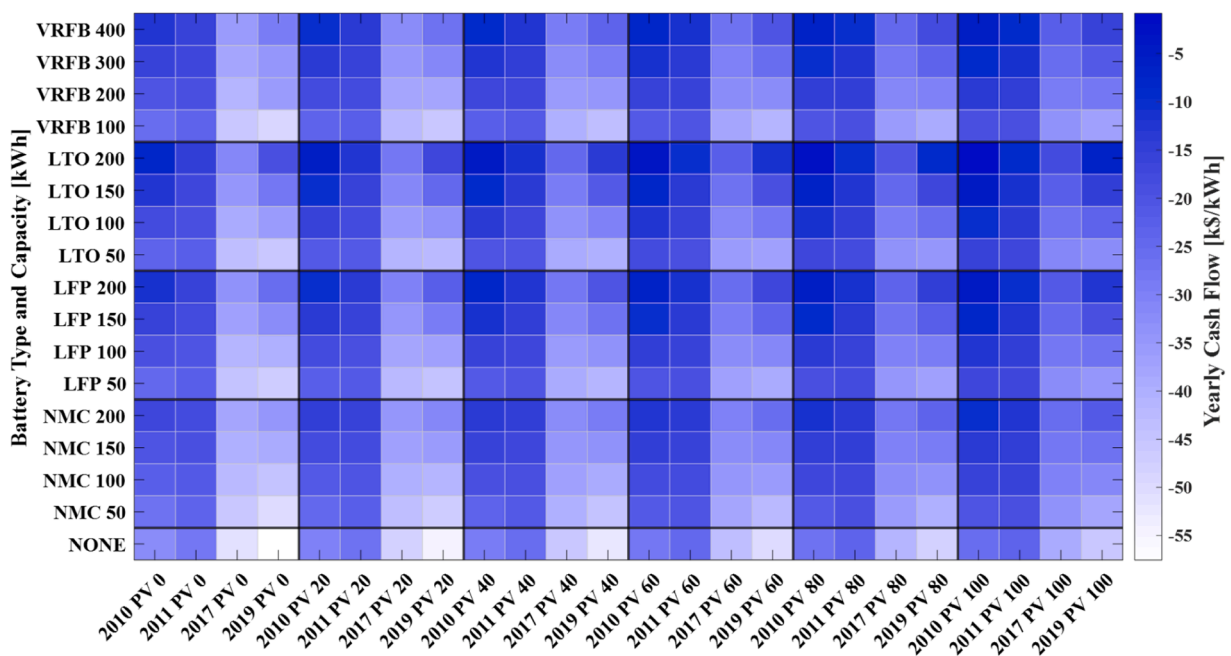


Fig. 8. Yearly cash flow with different types of community batteries operating in the NEM. On the y-axis, the number refers to the battery type and capacity [kWh]. On the x-axis, the year and the additional nominal PV generation [kW] are displayed.

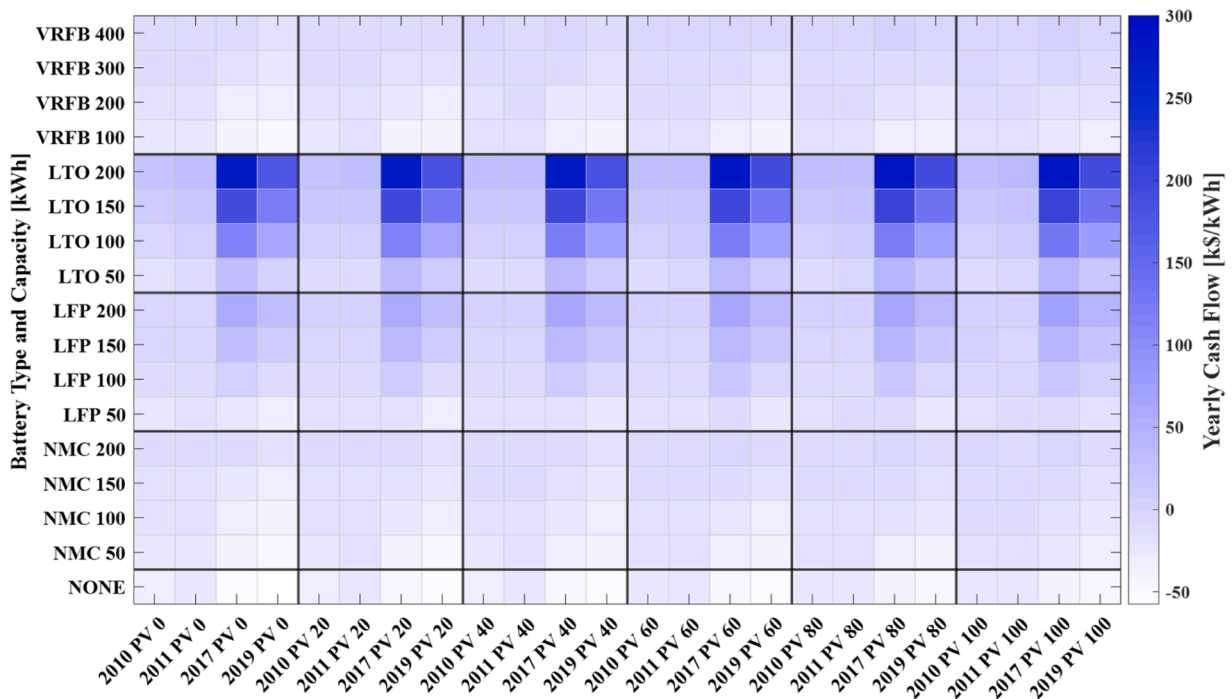


Fig. 9. Yearly cash flow with different types of community batteries operating in the NEM and FCAS market. On the y-axis, the number refers to the battery type and capacity [kWh]. On the x-axis, the year and the additional nominal PV generation [kW] are displayed.

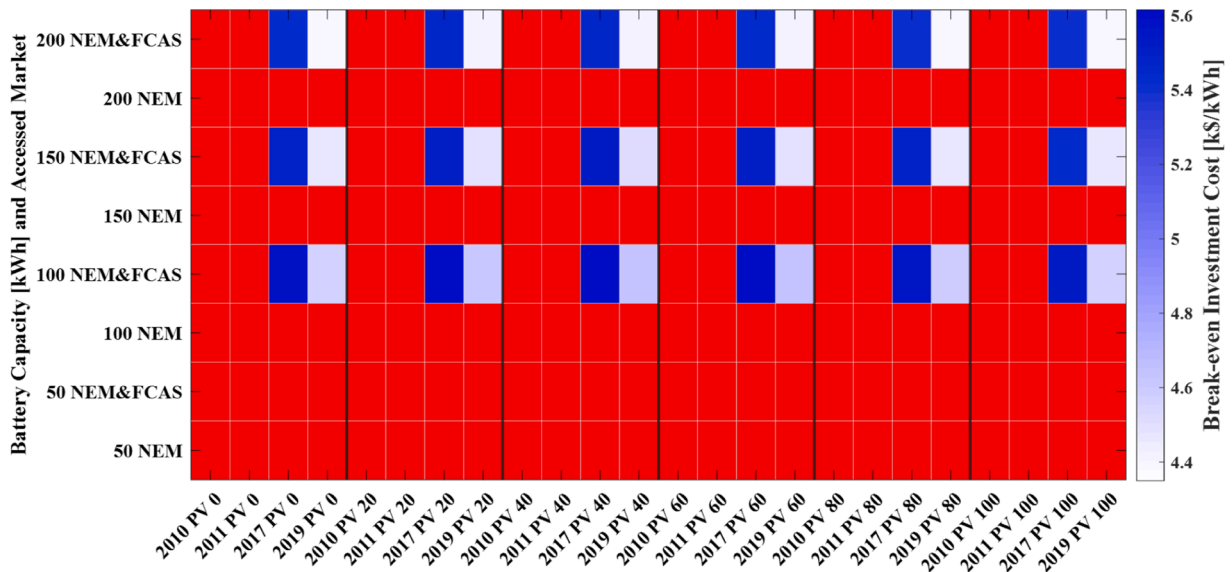


Fig. 10. Break-even investment costs for community LFP battery-PV system. On the y-axis, the number refers to the battery capacity [kWh] and the acronym refers to the accessed markets. On the x-axis, the year and the additional nominal PV generation [kW] are displayed. Red cells indicates unprofitable investments.

expected direction, however, the magnitude of these shifts is relatively modest compared to the influence of market conditions. Even a 30% reduction in capital cost fails to turn most unprofitable investments into profitable ones. Similarly, an increase of 30% in capital costs does not transform most profitable investments into unprofitable ones. This is particularly evident for costlier technologies. The cases of LTO and VRFB deserve a special mention. For the LTO technology, a reduction in the capital cost of 40% shows 3 profitable systems only participating in the NEM at the market prices of 2019, characterized by small battery size (50 kWh and 100 kWh) and large PV generation (80 kW and 100 kW). With a reduction of capital cost of 50%, the LTO CBs participating only in the NEM are profitable at every investigated size when

coupled with 80 kW and 100 kW of PV for the market prices of 2019. Under the same conditions, the LTO CBs coupled with 60 kW of PV are not profitable only for a capacity of 200 kWh. Price reductions in the capital cost of the VRFB of 40% and 50% make the system VRFB-PV profitable in all the investigated conditions, with the only exception of 400 kWh VRFB coupled with 100 kW PV at the market prices of 2017.

This finding reinforces the conclusion that profitability depends more strongly on policy-driven revenue structures than on incremental technological cost reductions. For example, the volatility of wholesale prices and, particularly for LFP and LTO CBs, the level of FCAS availability payments exert a much stronger effect on BIC than capital expenditure adjustments within the tested range. Investment costs are

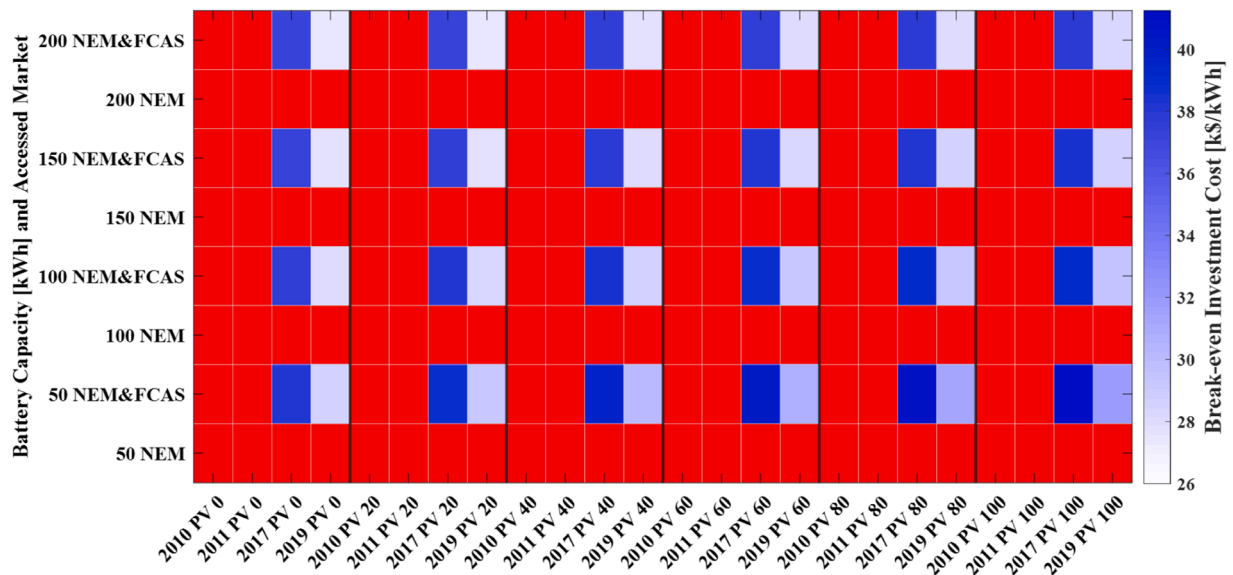


Fig. 11. Break-even investment costs for community LTO battery-PV system. On the y-axis, the number refers to the battery capacity [kWh] and the acronym refers to the accessed markets. On the x-axis, the year and the additional nominal PV generation [kW] are displayed. Red cells indicates unprofitable investments.

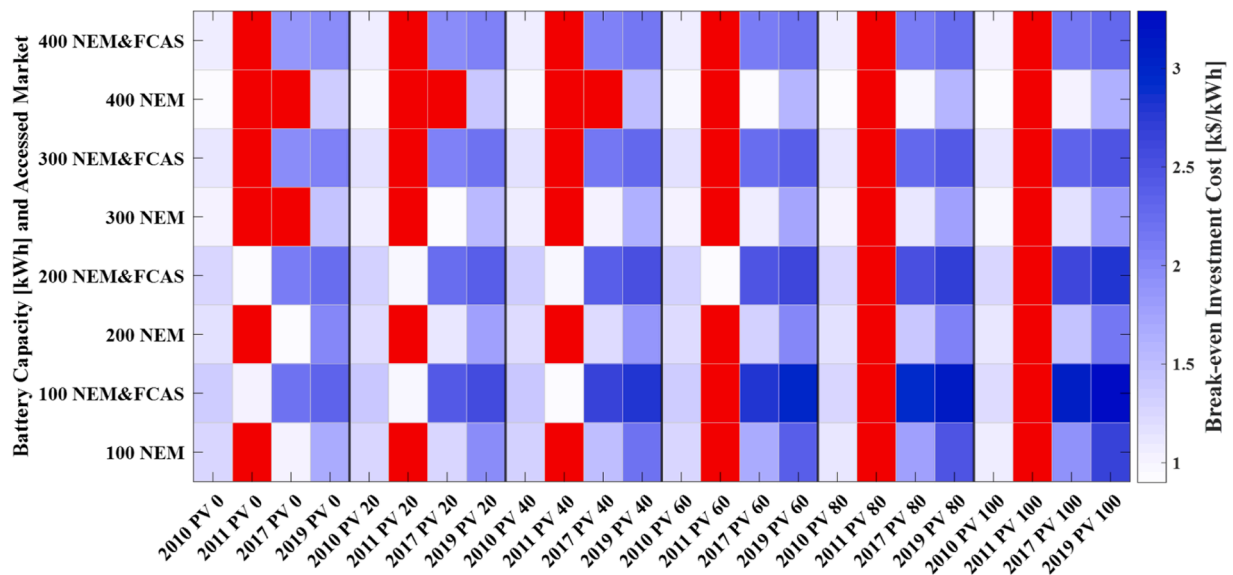


Fig. 12. Break-even investment costs for community VRFB-PV system. On the y-axis, the number refers to the battery capacity [kWh] and the acronym refers to the accessed markets. On the x-axis, the year and the additional nominal PV generation [kW] are displayed. Red cells indicates unprofitable investments.

therefore a secondary determinant relative to market access and design. The exception is VRFB technology, where cost variations have a more tangible impact on BICs due to its larger reliance on energy arbitrage and lower reliance on ancillary services with respect to the other technologies. In this case, moderate CAPEX reductions can expand the range of profitable scenarios, although market conditions remain the dominant driver overall.

From a strategic standpoint, this analysis suggests that continued cost declines in storage technologies, while beneficial, are unlikely to be sufficient to ensure widespread adoption of CBs. Policy interventions that secure stable and fair participation in FCAS market will have a far greater impact on deployment. Therefore, CBs should be viewed primarily as policy-enabled assets rather than purely technology-driven ones. Long-term viability will depend not only on advances in electrochemistry but also, and more decisively, on the regulatory frameworks that determine how these assets are integrated into energy systems and

compensated for their services.

5.6. Final remarks and policy highlights

The simulations confirm that multi-market participation is pivotal for the profitability of CBs, with high-power availability emerging as a key factor influencing outcomes. Sensitivity analysis on investment costs (see [Supplementary Material](#)) shows that cost variations have limited influence compared to market conditions: more affordable chemistries recover costs across a wider range of scenarios, while high-power batteries, despite their elevated prices, deliver substantial profits only when market prices are favorable. Overall, market dynamics remain the dominant driver of investment viability.

A notable exception is the VRFB, whose profitability is more responsive to capital cost reductions, indeed lower costs can materially expand the set of profitable configurations, underscoring the importance

of considering technology-specific sensitivities when designing support schemes.

Across all technologies, the most decisive factor is participation in FCAS markets. In the Australian framework, contingency FCAS remunerates availability rather than actual energy delivery, enabling batteries to secure revenues by reserving capacity for frequency deviations. High FCAS prices consistently drive investments toward profitability, even when wholesale energy prices are less favorable. These results underline that policy mechanisms, particularly the structure of ancillary service markets, are more influential for CBs business models than purely technical performance parameters such as RTE.

Table 6 synthesizes the main findings, while Table 7 outlines the corresponding policy highlights and offer valuable recommendations to the different stakeholders involved in the energy community.

6. Conclusions

This paper has presented a technological overview and a comprehensive techno-economic assessment of community batteries within energy communities. By combining a comparative review of key battery chemistries with an optimization model applied to an Australian case study, we have shown how technical characteristics translate into operational suitability and economic feasibility.

Although the case study is based on a single host site, the findings are directly relevant to energy community initiatives operating under similar regulatory and market conditions, as they highlight how shared storage assets can enable renewable integration and system-level flexibility while reducing individual investment barriers. All modeling assumptions and parameter values are explicitly reported to ensure replicability. While alternative assumptions may shift quantitative outcomes, the qualitative ranking of technologies and the dominant role of

Table 6
Summary of the results.

No CB	<ul style="list-style-type: none"> • Average prices determines the goodness of the investments. The higher the average price, the higher the BIC • Increasing the PV generation increases the YCF but reduces the BIC
CB in the NEM	<ul style="list-style-type: none"> • Price volatility matters the most in generating higher YCFs. The higher the volatility and the average price the higher the BIC
CB in the NEM and FCAS market	<ul style="list-style-type: none"> • Cost-effective investments are the only profitable <ul style="list-style-type: none"> ◦ VRFB is the best solution to adopt and can be profitable also at unfavorable market conditions ◦ NMC batteries are profitable at favorable market conditions ◦ LFP and LTO batteries are never profitable • The effect of the battery RTE is marginal with respect to the other parameters • FCAS market participation is game changing. The higher the average FCAS price the higher the BIC • High average wholesale market price and volatility matters only for technologies with high E/P ratio <ul style="list-style-type: none"> ◦ VRFBs are profitable at most market conditions and PV generation levels ◦ Given all other conditions, NMC batteries are more likely to be profitable, or to show a larger BIC, at small capacity • For low E/P-ratio technologies only matters average FCAS prices. The higher the average price the higher the BIC, regardless of the wholesale market prices. <ul style="list-style-type: none"> ◦ Low E/P-ratio technologies, <i>i.e.</i>, expensive technologies are profitable only at high average FCAS prices ◦ The lower the E/P ratio the less sensitive to installed battery capacity <ul style="list-style-type: none"> ▪ LFP batteries are profitable at large capacities under favorable market conditions, with lower PV generations returning higher BICs ▪ LTO batteries are profitable at every battery capacity under favorable market conditions • The effect of the battery RTE is marginal with respect to the other parameters

Table 7
Policy highlights.

Market design matters more than CAPEX:	<ul style="list-style-type: none"> • Profitability of CBs is shaped primarily by FCAS prices and market volatility. • Moderate variations in technology investment costs have small effect.
Ancillary services are decisive:	<ul style="list-style-type: none"> • Participation in FCAS market can transform otherwise unprofitable CB investments into viable ones, with high-power LiBs unlocking annual revenues exceeding 300,000 \$ per year under favorable conditions.
Technology choice should match community goals:	<ul style="list-style-type: none"> • VRFBs offer safe, durable, and scalable storage making them suitable for communities seeking long-term, low-risk investments. • High-powers LiBs, <i>e.g.</i>, LFP and LTO, are viable only where FCAS revenues are significant, and thus require mature service markets.
Policy support should target market access:	<ul style="list-style-type: none"> • Subsidies for technology costs are less impactful than regulatory frameworks that ensure CBs can access and be fairly remunerated in service markets
Energy communities as flexibility providers:	<ul style="list-style-type: none"> • Recognizing CBs as legible participants in system-level markets is critical for aligning community-level decarbonization with broader grid stability needs.

market access remain robust.

The results highlight that community batteries profitability is highly contingent on market structures. Participation in the frequency control ancillary services market fundamentally shifts the investment outlook under current Australian market price conditions, with high prices enabling positive returns even for costly, high-power lithium-ion chemistries. By contrast, wholesale energy arbitrage alone rarely yields sufficient revenues. Within the framework of the considered case study and market conditions, Vanadium redox flow batteries emerge as the most cost-effective option among the technologies analyzed, owing to their scalability, long lifetime, and decoupled energy and power ratings.

The supplementary sensitivity analysis confirms that moderate variations in investment costs ($\pm 30\%$) have only marginal influence on break-even investment costs compared to market price conditions. The only notable exceptions are the Vanadium redox flow technology, where CAPEX reductions can substantially expand the set of profitable configurations, and LTO technology, where large CAPEX reductions (40% and 50%) bring few CB-PV systems to be profitable when participating only in the NEM. However, even in this case favorable market and policy conditions remain the decisive factor for long-term viability.

These findings underscore that policy and market design, particularly access to and remuneration from ancillary services, are more decisive for CB viability than incremental CAPEX reductions. Rather than asserting universal optimality or quantitative outcomes, the findings of this paper provide transferable qualitative insights into how market access and technological characteristics interact within a community battery framework. Within this context, the results suggest that: (i) communities seeking safe and reliable investments should prioritize cost-effective and durable technologies such as Vanadium redox flow batteries; (ii) policymakers should focus less on subsidizing technology costs and more on ensuring stable and accessible service markets; and (iii) regulators should recognize community batteries as key enablers of distributed flexibility, worthy of explicit support within energy community frameworks.

Future work may extend the proposed framework to aspects that are not directly addressed in this paper, such as including degradation-aware dispatch, detailed FCAS enablement constraints and saturation, and network-constrained operation for site-specific assessments.

CRedit authorship contribution statement

Carmen Bas Domenech: Writing – original draft, Visualization, Methodology, Investigation, Formal analysis, Data curation,

Conceptualization. **Francesco Conte**: Writing – review & editing, Supervision, Resources. **Pierluigi Mancarella**: Writing – review & editing, Supervision, Project administration, Conceptualization. **Gianluca Natrella**: Writing – original draft, Visualization, Methodology, Investigation, Formal analysis, Data curation, Conceptualization.

Declaration of Competing Interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Francesco Conte reports financial support was provided by European Union. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at [doi:10.1016/j.segan.2026.102229](https://doi.org/10.1016/j.segan.2026.102229).

Data availability

The data that has been used is confidential.

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