Co-optimization of Behind-the-meter and Front-of-meter Value Streams in Community Batteries

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***Abstract*—Community batteries (CBs) are emerging to support and even enable energy communities and generally help consumers, especially space-constrained ones, to access potential techno-economic benefits from storage and support local grid decarbonization. However, the economic viability of CB projects is often uncertain. In this regard, typical feasibility studies assess CB value for behind-the-meter (BTM) operation or wholesale market participation, i.e., front-of-meter (FOM). This work proposes a novel techno-economic operational framework that allows systematic assessment of the different options and introduces a two-meter architecture that co-optimizes both BTM and FOM benefits. A real CB project application in Australia is used to demonstrate the significant two-meter co-optimization opportunities that could enhance the business case of CB and energy communities by multi-service provision and value stacking.**

***Index Terms*—Behind-the-meter, community battery, distributed energy resource (DER), energy community, front-of-meter, value stacking.**

I. Introduction

MANY countries worldwide have very ambitious environmental targets. Australia, for instance, aims for renewable energy sources to account for over 80% of its electricity mix by 2030 [1], and is leading the world in the adoption of distributed energy resources (DERs), particularly rooftop photovoltaic (PV) [2]. Nevertheless, accommodating such large shares of distributed PV comes with significant challenges, especially in low-voltage (LV) distribution networks (DNs), such as curtailment of PV generation to ensure DN integrity and/or costly reinforcements [3]. This calls for new, cost-efficient technical and economic solutions at LV level. At the same time, energy communities are emerging as citizen-driven initiatives that seek to promote local renewable energy and self-sufficiency [4]. In the context of energy communities, community batteries (CBs) offer a shared battery solution at LV level to access the multiple benefits of batteries, while supporting the self-sufficiency goals of energy communities [5], [6]. While there is no generally accepted definition of CB, we follow the concepts discussed in [7], hence CBs are resources that serve a group of citizens united by a common objective. By better utilizing the locally produced renewable energy, CB can reduce local solar energy curtailment and/or avoid network reinforcements to export excess renewable generation to the upstream grid.

An important CB use case is in urban areas, where residents may live in rental properties or high-rise apartment buildings, and generally cannot install privately-owned batteries. Moreover, when compared with privately-owned batteries, CB presents attractive attributes [8]. For instance, the potentials include leveraging the demand and generation diversity existing at community-level, which may decrease the total size of storage requirement, and reducing per-kW investment costs by installing larger assets that benefit from economies of scale [9]. In fact, existing literature has demonstrated that CB shows improved utilization and techno-economic results than privately-owned batteries [8], [10]. Moreover, as larger assets, CBs can readily engage with market players such as aggregators to effectively access all suitable markets [11].

In spite of several potential benefits, the viability of CB projects is often uncertain due to storage costs, existing tariff structures, etc. [12]. Hence, there is a growing interest in exploring new ways to improve CB economic feasibility. Significant work addressing the CB commercial viability has focused on policy development issues, without a supporting techno-economic analysis [13], [14]. Besides, techno-economic studies consider a CB installed in a host site, e.g., a commercial or apartment building, and two distinct architectures, i. e., behind-the-meter (BTM) and front-of-meter (FOM) architectures. BTM and FOM are used to highlight the CB coordinated with other local resources with respect to an upstream meter (as BTM); or independently operated and metered to face system-level markets (as FOM). More specifically, when the CB is dispatched considering the demand and generation of the host site, and netting the total metered imports and exports to provide economic savings, e.g.,

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through tariff price arbitrage or peak demand charge reduction, BTM value streams are accessed [12], [15], [16]. In the FOM option, the CB revenues that are shared with the community come from the system-level market participation. The CB operation is dictated by market/service prices, independently from the host site, and BTM value streams are not accessed [12], [17].

Overall, most research works have focused on BTM value streams, due to CB typically experiencing fewer barriers to access these benefits [18]. This could be explained with the perceived disconnection between the policy and regulatory perspectives and the development of relevant mathematical models to quantify the CB economic value. Crucially, there is no framework that looked into co-optimizing both BTM and FOM value streams, which is a significant research gap in the development of commercially viable CBs. In this context, co-optimization refers to the optimization of resources to simultaneously access two or more interdependent value streams, also referred as multi-commodity optimization. Furthermore, there are virtual power plant (VPP) frameworks that illustrate co-optimized participation in multiple services, demonstrating the potential from value stacking (via accessing and ideally optimising) several value streams while reducing the energy costs of the consumers [19], [20]. Value stacking can also enhance storage investment viability through the management of price uncertainty risk [21]. The main caveat of the existing research works of VPP co-optimization is that they assume that consumers within the VPP are subject to system-level market prices to meet their energy demand. On the one hand, they often miss network tariffs and relevant BTM value streams, such as peak demand charge reduction. On the other hand, these approaches will likely face some barriers in their practical implementation as consumers rarely have the risk profile to face the price volatility of system-level markets.

In fact, existing commercial VPP reflect consumers' risk profile by offering a fixed energy price and feed-in tariff, which is more attractive than regular retail tariffs. In exchange, consumers allow the VPP to control their DER for a number of events, ensuring that some DER capacity is left to meet the consumer's energy needs [22]. Given these limitations, VPP mostly participates in ancillary services, like contingency frequency control ancillary services (FCASs) [23], in which most revenues come from availability rather than delivery [19]. Moreover, VPP market participation is rarely co-optimized with network support, e.g., peak demand reduction, as it requires network support agreements that the DN operator is not incentivized to access [24]. Overall, the VPP business case, mostly targeting residential consumers, is generally not conducive to the potential co-optimization of BTM and FOM value streams that a CB connected to a large consumer could access. This issue highlights the research gap addressed in this paper, i. e., co-optimization of BTM and FOM value streams, as well as the potential of CBs to provide a distinct business case when compared with existing VPPs.

While the co-optimization of BTM and FOM value streams can be crucial to enhance CB viability, practical implementations require a new hybrid architecture. One architecture is that it recognizes BTM simplicity of operation for consumers who often prefer to operate with relatively simple retail tariffs, and the FOM opportunities that might arise for system-level services within current and future regulatory environments. The main contributions of this work are:

1) Proposal of a novel hybrid architecture that bridges the gap between commercial analysis and mathematical modelling allowing co-optimization of BTM and FOM value streams in a CB installed in a relatively large customer.

2) Development of a general and architecture-agnostic CB operational framework that allows to seamlessly compare the techno-economic performance of various CB architectures, with a realistic model and logic capturing the annual costs and benefits of customers, for a lifetime assessment of CB.

3) Exemplification of a practical application of the proposed CB operational framework and the proposed hybrid architecture to perform a comparative study to determine key techno-economic parameters for the economic feasibility of a CB in a real Australian project, including exploring the impact of different network tariffs, market conditions, and CB energy to power ratios.

The remainder of the paper is structured as follows. Section II discusses the techno-economic setup and the three CB architectures. Section III introduces the proposed CB operational framework. Section IV presents the real case study application and Section V discusses its results. Finally, Section VI presents the concluding remarks of this work.

II. Techno-Economic Setup and Three CB Architectures

This section outlines the techno-economic setup to study different CB value stream opportunities and introduces three different CB architectures that could be considered, including the BTM, the FOM, and the proposed hybrid architectures. It should be noted that while the Australian context is taken as reference here, the general concepts and mathematical modelling presented are completely general and could be readily extended to different jurisdictions worldwide.

A. System Setup

The system setup is comprised of the CB and a host site with an energy demand, i. e., load and PV, as presented in Fig. 1. Figure 1 also displays two meters, i. e., the gate meter, which is connected at the interface between the host site and the upstream grid, and the child meter, which is connected to the CB, directly metering its output.

B. CB Accessible Value Streams

In terms of FOM value stream, the CB can access the wholesale energy market and FCAS via the child meter, i.e., market-facing meter. The CB can first of all accrue price arbitrage revenues by leveraging the market volatility, charging with low prices, and discharging with high prices. Six contingency FCASs are then available, grouped as fast, slow, and delayed raise/lower, based on type of response required, response time, and service duration [25]. Since most revenues from FCAS participation are a result of availability, instead of delivery [19], the feasibility analysis conservatively only considers availability payments. It should be noted that ancillary services are widespread mechanisms in different jurisdictions [26]. While the general framework can be applied to different markets, the service duration, response time, and the number of accessible markets for CB may vary. Additionally, the CB can provide network demand response (DR) services to manage electricity demand under peak conditions. Currently, DR contracts are included in the planning reports by the DN operators as non-network solutions [27]. Network DR services require the resource to commit a capacity during a certain period, e.g., summer, ensuring that the capacity can be delivered when the DR service is called, resulting in availability payments. DR delivery is also limited to a predefined number of events with a fixed duration and associated DR delivery payments. The commitment of DR capacity and ability to provide DR at any point during the contractually agreed period is the most limiting constraint for CB co-optimization and the main source of DR revenues [28]. DR delivery and associated revenues can be estimated with the number of DR events in the contract and suitable assumptions when DR events may be called on, e.g., by considering previous DR events or historical peak demand data. DR delivery is included in the proposed modelling in a flexible manner by providing parameters related to the expected DR events, which can be tuned to zero, for a conservative analysis assuming that no DR events are called.

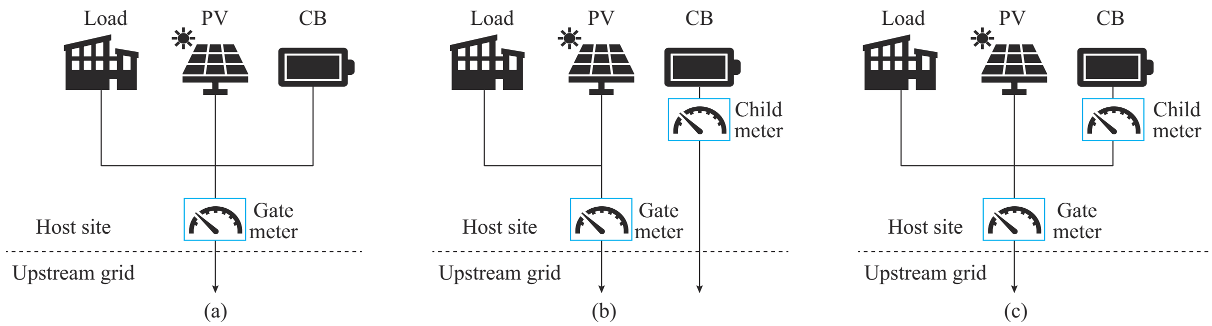

Fig. 1. Example diagram. (a) BTM architecture. (b) FOM architecture. (c) Proposed hybrid architecture.

In terms of BTM benefits, customers normally enter a contract with a retailer that charges them for energy according to a retail tariff. Retail tariffs are generally comprised of two main components, i.e., energy market and network components. If the retail tariff has prices varying throughout the day, the CB can engage in arbitrage resulting in economic savings for the host site. Additionally, the network component for large costumers often includes a cost based on the maximum demand, i.e., peak demand charge, during a predefined time window, e.g., the specific billing period, for instance one month or three months. Hence, the CB can also be controlled to shave the demand peaks and thus reduce associated costs, which is achieved by demand netting with respect to the gate meter.

In the current regulatory framework, the CB can access the value streams mentioned above with limited regulatory barriers, as previously reported in [28]. Moreover, in the Australian context, there are further value streams the CB could access, e.g., reliability and emergency reserve trader [29], incentive scheme of service target performance [30], and local network support. However, the lack of available data and uncertainty on the CB ability to monetize these value streams result in the omission of these value streams in this paper.

C. Metering Architectures

Three different architectures that enable the CB to access different value streams are discussed below.

1) BTM Architecture

The BTM architecture is comprised of one single meter, i.e., the gate meter, as depicted in Fig. 1. The BTM architecture allows to coordinate all the resources downstream the gate meter and their operation is netted with respect to this meter. This enables the CB to provide energy arbitrage to the host site by reducing retail costs, which might include a peak demand charge in the network component of the retail tariff.

2) FOM Architecture

The FOM architecture has a child meter that directly meters the CB performance in the provision of different system-level markets and services. The host site is operated independently, with the CB not being connected to the gate meter and thus not providing any BTM benefit.

3) Proposed Hybrid Architecture

A hybrid architecture is proposed as a key novelty to understand the CB potential to co-optimize FOM and BTM value streams. The proposed hybrid architecture is comprised of two meters: the gate meter and the child meter. This architecture allows to access both BTM and FOM value streams, as displayed in Fig. 1.

In the proposed hybrid architecture, the gate meter measures the total energy imports/exports of the host site, PV system, CB, and the peak demand. The child meter is located at the CB, directly metering the CB charging and discharging to measure its performance in different system-level markets. FOM and BTM value streams can be accessed by the CB with certain caveats. In this architecture, the CB imports/exports are metered twice by the child meter and by the gate meter. Therefore, a netting transaction between the host site and the CB is carried out to avoid this double counting, effectively making the host site a "net zero-sum actor" with respect to retail energy costs. The modelling framework nets this double counting after the operation of the CB is optimized to maximize revenues. Transactions are computed assuming there are no revenues or costs arising from the CB operation with respect to the retail energy costs of host site. However, the CB co-optimizes FOM value stream while accessing BTM value stream by reducing the peak demand charges of the host site.

In practice, the proposed hybrid architecture resembles existing embedded network frameworks, i.e., a private network that serves multiple premises, such as apartment blocks, found in different regions of the world. The child meter provides additional visibility and control of the CB, which may be used in the future by DN operators or market operators in network or market-driven events. While there are no prescriptive regulatory frameworks readily available for energy communities, the engagement with different actors is crucial for CB to support the energy transition, and future work will explore the techno-economic impact of regulatory issues.

III. Proposed CB Operational Framework

This section presents the proposed CB operational framework, which involves a techno-economic model that seamlessly includes three different architectures presented in Section II-C, thus allowing to assess the co-optimization of both FOM and BTM value streams with a proposed hybrid architecture.

The proposed framework is formulated in a general and flexible manner and can support studies ranging from a single host site with CB to a CB network with associated host sites. The proposed framework is formulated as a multi-period second-order cone program. A second-order cone formulation is computationally efficient and allows accurate modelling of converter-interfaced DER and DN operation. While DN operation is not in the scope of this paper, the proposed framework can be seamlessly expanded by including the optimal power flow of second-order cone [31], supporting future work in energy communities. Moreover, the proposed second-order cone constraints can be accurately linearized using a lifted polyhedron approximation [32]. Binary variables, often used to prevent simultaneous battery charging and discharging or to model feed-in tariffs for customer exports, are avoided without any loss of accuracy by using mild conditions and leveraging the cost minimization formulation of the problem. The specific conditions which avoid binary variables are presented along the relevant constraints.

A. Notation

Let Ω_N denote the collection of host sites, Ω_B denote the collection of CBs, and Ω_B^n denote the CB connected to host site n. Binary parameters Ψ_n^{BTM}, Ψ_n^{FOM}, and Ψ_n^{H} denote the BTM, FOM, and hybrid architectures in host site n, respectively, as described in Section II-C. Additionally, Φ_R denotes the set of frequency raise services, whereas Φ_L denotes the set of frequency lower services.

Finally, the parameter Ψ_n^{PV} is deployed for completeness, ensuring that different types of energy communities can be studied with the proposed framework. When $\Psi_n^{PV}=0$, the PV system is owned by the host site with its output measured by the gate meter, as depicted in Fig. 1. Conversely, $\Psi_n^{PV}=1$ allows modelling the case in which PV and CB share the meter installation, with their net output measured by the child meter in the FOM and the proposed hybrid architectures. Whilst for brevity and without loss of generality, the results of the setup $\Psi_n^{PV}=1$ will not be presented in this paper. The applicability of the proposed framework is ensured to future work of co-optimizing value streams within energy communities with even broader DER arrangements. It should be noted the formulation assumes that PV cannot participate in FCAS or provide DR services.

B. Architecture-agnostic Objective and Cost Function

The architecture-agnostic objective and cost function is presented in (1), where the costs of FOM and BTM value streams c^{FOM} and c^{BTM} are minimized for each time-step during the billing period T^{BP}. The deployment of parameters Ψ_n^{BTM}, Ψ_n^{FOM} and Ψ_n^{H} is such that only one of these parameters is 1 in each host site n, enabling an architecture-agnostic formulation in (1), which allows the co-optimization of BTM and FOM value streams when $\Psi_n^{H}=1$, as well as only BTM or FOM value streams (for $\Psi_n^{BTM}=1$ and $\Psi_n^{FOM}=1$, respectively). The architecture parameters are constrained by (2).

$$\min\left[\sum_{t=1}^{T^{BP}}\left(c^{FOM}(t)+c^{BTM}(t)\right)+\sum_{n\in\Omega_N}\max\left(\Psi_n^{BTM},\Psi_n^{H}\right)\lambda_n^{PC}S_n^{\max}-\sum_{n\in\Omega_N}\max\left(\Psi_n^{FOM},\Psi_n^{H}\right)\lambda^{DR,cap}p_b^{DR,cap}\right] \tag{1}$$

$$\Psi_n^{BTM}+\Psi_n^{FOM}+\Psi_n^{H}=1 \tag{2}$$

Peak demand is charged once during the billing period and is minimized by the CB in the BTM and proposed hybrid architectures, according to the peak demand price λ_n^{PC} ($/MVA) and apparent power at the gate meter $S_n^{\max}$ (MVA). The formulation assumes perfect foresight of demand and market prices to provide the optimal peak demand reduction as a result of the CB operation. In practice, the peak demand projected by the proposed framework could be used as a control signal, prompting the CB to adjust its dispatch to ensure that the demand at the gate meter does not surpass the peak demand derived from the proposed framework. Network DR payments for availability are revenues accrued once during a billing period in FOM and the proposed hybrid architectures, considering price $\lambda^{DR,cap}$ ($/MW) and the committed CB capacity by the CB $p_b^{DR,cap}$ (MW).

BTM value streams are calculated in (3). Two strategies are deployed to avoid simultaneous charging and discharging, including artificial costs for charging and discharging (C_b^{ch} and C_b^{dh} ($/MWh), respectively) as well as charging and discharging efficiencies of different values. At the same time, in energy cost minimization problems, tuning these cost parameters to a relatively small value, e.g., 1 $/MWh, has minimal impact on optimality [33] with current retail and wholesale energy market prices. The CB will not be dispatched with energy prices $\lambda_t^{WS}\in(-1,1)$$/MWh, as CB operational costs will be higher than revenues from energy market participation. If energy prices are predominantly expected in this range, CB operational costs should be tuned to ensure CB dispatch.

$$c^{BTM}(t)=\sum_{n\in\Omega_N}\Psi_n^{BTM}\left(C_b^{dh}p_b^{dh}(t)+C_b^{ch}p_b^{ch}(t)-\beta_n^{RT}(t)\right)\Delta t \tag{3}$$

where p_b^{ch} and p_b^{dh} (MW) are the CB charging and discharging power, respectively; β_n^{RT} (\$/MWh) is an auxiliary variable representing the energy cost of retail tariff for the host site (comprised of the energy market and network cost component); and Δt (hour^{-1}) is the parameter representing the time-step duration. FOM value streams, accessible in the FOM and proposed hybrid architectures, are calculated as in (4). CB operational costs are included, as previously described. The net output of the CB p_b (MW) is multiplied by λ_t^{WS}, so that when the CB is selling energy to the market, it is considered as a revenue and when the CB is buying energy, it is a cost. The next two terms correspond to the revenues accrued by FCAS participation. For raise FCAS, revenues are a function of the service price, i.e., λ_t^r (\$/MWh), and the power committed by the CB for each raise service p_b^r (MW). The same is replicated for lower FCAS using λ_t^l (\$/MWh) and p_b^l (MW). Finally, the revenues for DR delivery are included as a function of the DR delivery price $\lambda^{DR,dlv}$ (\$/MWh), the CB DR delivered $p_b^{DR,dlv}$ (MW), and the parameter $\zeta_t^{DR,dlv}$ that encodes when the DR event is assumed to be expected to be called. The details on the assumption of DR events are presented in Section III-D.

$$c^{FOM}(t)=\sum_{n\in\Omega_N}\max\left(\Psi_n^{FOM},\Psi_n^{H}\right)\sum_{b\in\Omega_B^n}\Bigg(C_b^{dh}p_b^{dh}(t)+C_b^{ch}p_b^{ch}(t)-\lambda_t^{WS}\left(p_b(t)+\Psi_n^{PV}p_{PV}(t)\right)-\sum_{r\in\Phi_R}\lambda_t^r p_b^r(t)-\sum_{l\in\Phi_L}\lambda_t^l p_b^l(t)-\zeta_t^{DR,dlv}\lambda^{DR,dlv}p_b^{DR,dlv}(t)\Bigg)\Delta t \tag{4}$$

C. CB Operation

CB operation is modelled in (5)-(12), where $b\in\Omega_B$, $t\in T^{BP}$.

$$\begin{cases}0\le p_b^{ch}(t)\le\bar{p}_b^{ch}\\ 0\le p_b^{dh}(t)\le\bar{p}_b^{dh}\end{cases} \tag{5}$$

$$p_b=p_b^{dh}(t)-p_b^{ch}(t) \tag{6}$$

$$\underline{q}_b\le q_b(t)\le\bar{q}_b \tag{7}$$

$$\left\|\begin{bmatrix}p_b(t)\\ q_b(t)\end{bmatrix}\right\|\le S_b(t) \tag{8}$$

$$0\le x_b(t)\le 1 \tag{9}$$

$$E_b\left(x_b(t+1)-x_b(t)\right)=\left(\eta_b^{ch}p_b^{ch}(t)-\frac{p_b^{dh}(t)}{\eta_b^{dh}}\right)\Delta t \tag{10}$$

$$E_bN_b\frac{T_{BP}\Delta t}{24}\ge\sum_t^{T_{BP}}p_b^{dh}(t)\Delta t \tag{11}$$

$$\underline{\rho}_b\Delta t\le p_b(t)-p_b(t-1)\le\bar{\rho}_b\Delta t \tag{12}$$

In (5), the CB charging power and discharging power are defined as positive variables, limited by their maximum charging power and discharging power $\bar{p}_b^{ch}$ and $\bar{p}_b^{dh}$ (MW), respectively. The net output of the CB is defined in (6), establishing the sign convention of positive generation and negative consumption. The CB reactive power output q_b (Mvar) is limited by the CB reactive power limits $\underline{q}_b$, $\bar{q}_b$ (Mvar) in (7). Four-quadrant operation of CB, limited by their rated power S_b, is established in (8) using a second-order cone constraint. This constraint can be linearized using the lifted polyhedron approximation [32]. Constraint (9) sets the upper and lower bounds of the normalized CB state-of-charge (SoC) x_b. The energy balance of the CB is modelled in (10), where E_b (MWh) is the CB nameplate capacity. The battery charging and discharging efficiencies η_b^{ch},η_b^{dh} must be different to avoid simultaneous charging and discharging, as well as including CB operational costs. Manufacturers provide a maximum energy throughput (defined as the total discharged energy) or a maximum number of cycles per day, both for a given battery lifetime. Once the battery exceeds these limits, manufacturers no longer guarantee its performance and reliability, with the battery capacity significantly reduced, beyond 70% of the nameplate capacity [34]. These limits are generally not considered in the existing literature. However, they may have a very material impact on the CB operation and opportunities to accrue revenues. In (11), the energy throughput during a billing period is limited given the CB nameplate capacity, number of cycles per day N_b, and the number of days during a billing period. If the manufacturer provides the maximum energy throughput, N_b can be calculated dividing the maximum energy throughput by the battery lifetime (in days). It must be noted that by limiting the energy throughput as opposed to the cycles per day, additional flexibility is unlocked for the battery to sustain further cycles when more revenues or savings can be accrued during a billing period. Finally, (12) governs the ramp rates of the CB according to its minimum and maximum ramp rates $\underline{\rho}_b$, $\bar{\rho}_b$ (MW/h).

D. Service Provision

The constraints in (13)-(18) [19] ensure that the CB can deliver FCAS.

$$0\le p_b^r(t)\le\bar{\rho}_b\tau^r \tag{13}$$

$$0\le p_b^l(t)\le-\underline{\rho}_b\tau^l \tag{14}$$

$$-\bar{p}_b^d\le p_b(t)+p_b^r(t)\le\bar{p}_b^g \tag{15}$$

$$-\bar{p}_b^d\le p_b(t)-p_b^l(t)\le\bar{p}_b^g \tag{16}$$

$$E_bx_b(t)\ge\sum_{r\in\Phi_R}\frac{1}{\eta_b^g}\left(p_b(t)+p_b^r(t)\right)\delta^r \tag{17}$$

$$E_b\left(1-x_b(t)\right)\ge\sum_{l\in\Phi_L}\eta_b^d\left(p_b(t)-p_b^l(t)\right)\delta^l \tag{18}$$

The raise and lower services are modelled in (13) and (14), limited by the CB ramp rate limits and the response time for the raise and lower services (τ^r and τ^l, respectively). The participation in the different services is limited by the maximum CB charging and discharging power in (15) and (16), respectively. Additionally, (17) and (18) ensure that there is sufficient headroom/footroom to provide the raise and lower services for the duration of the service (δ^r and δ^l, respectively).

The provision of network DR by the CB is modelled in (19)-(23) considering capacity $p_b^{DR,cap}$ and delivery payments, as outlined in Section II-B.

$$p_b^{DR,cap}\le\bar{p}_b^{dh} \tag{19}$$

$$E_b x_b(t) \geq p_b^{DR,cap} \tau^{DR} \zeta_t^{DR,cap} \tag{20}$$

$$p_b^{DR,cap} \zeta_t^{DR,dlv} = p_b^{DR,dlv}(t) \tag{21}$$

$$\zeta_t^{DR,dlv} p_b^{dh}(t) = p_b^{DR,dlv}(t) \tag{22}$$

$$\sum_{t \in T^{BP}} \zeta_t^{DR,dlv} \leq \overline{\zeta}^{DR,delv} \tag{23}$$

The CB offers a capacity for DR, limited by its maximum discharging power in (19). Constraint (20) ensures that during all time periods, in which the CB has committed capacity for DR, there is enough storage for the required duration τ^{DR}. Binary parameter $\zeta_t^{DR,cap}$ encodes when the CB needs to reserve capacity as per the contractual agreement. When DR is called, the battery response is equal to the DR capacity offered by (21), using binary parameter $\zeta_t^{DR,dlv}$ which encodes the time-steps, in which the CB needs to deliver network DR. When DR events are called, i.e., $\zeta_t^{DR,dlv}=1$, the CB discharging power is defined by (22), ensuring that the CB is delivering the committed DR response during the event. Finally, (23) highlights the assumption required to model DR delivery, defining a maximum number of time-periods in which DR delivery $\overline{\zeta}^{DR,delv}$ is required, often limited by contractual agreement.

E. Host Site Operation

The host site operation is governed by (24)-(30).

$$p_{HS}(t) = \left(1-\Psi_n^{PV}\right) p_{PV}(t) - p_d(t) \quad p_{PV}(t) \geq 0, p_d(t) \geq 0 \tag{24}$$

$$p_n(t) = \max\left(\Psi_n^{BTM}, \Psi_n^{H}\right)\left(p_b(t) + \Psi_n^{PV} p_{PV}(t)\right) + p_{HS}(t) \tag{25}$$

$$q_n(t) = \max\left(\Psi_n^{BTM}, \Psi_n^{H}\right) q_b(t) + q_d(t) \tag{26}$$

$$\begin{cases} \beta_n^{RT}(t) \geq \lambda_t^{RT,+} p_n(t) \\ \beta_n^{RT}(t) \geq \lambda_t^{RT,-} p_n(t) \end{cases} \tag{27}$$

$$\left\| \begin{bmatrix} p_n(t) \\ q_n(t) \end{bmatrix} \right\| \leq S_n(t) \tag{28}$$

$$\overline{S}_n \geq S_n(t) \tag{29}$$

$$\overline{S}_n \geq S_n^{\max} \tag{30}$$

The host site net power p_{HS} is defined in (24) as the difference between the PV output p_{PV} (MW) and the building demand p_d (MW), both of which are positive variables. The total active and reactive power outputs of the gate meter are modelled in (25) and (26), considering the CB output is netted with the host site in BTM and the proposed hybrid architectures. The deployment of parameter Ψ_n^{PV} in (24) and (25) allows to model the case of PV system installed in the same child meter as the CB, allowing the proposed framework to represent further typologies of energy communities and support future work. Moreover, the underlying logic to include BTM and FOM resources presented in (24)-(26) could also be expanded to consider future active resources in various community setups. For example, future work may include resources, such as electric vehicles, which however require specific modelling assumptions on charging behavior. In addition, the proposed framework can support studies on the best system setup and architectures. Particularly, as new resources, such as EVs with community-level or household-level recharging technologies, are incorporated into energy communities.

Auxiliary variable β_n^{RT} is defined in (27). Parameters $\lambda_t^{RT,+}$ and $\lambda_t^{RT,-}$ (\$/MWh) are the retail prices for imports and exports, respectively, i.e., sum of the energy market and network components. As discussed in [35], under the mild condition $\lambda_t^{RT,+} \geq \lambda_t^{RT,-}$, different prices for imports/exports can be included without the need of binary variables. The apparent power at the gate meter S_n (MVA) is modelled by (28). The peak demand $\overline{S}_n$ is enforced to be the maximum apparent power by (29). In (30), the CB operation with a rolling peak demand is modelled using the parameter $S_n^{\max}$, which is the peak demand recorded during a past billing period. For instance, to analyze the whole year of CB operation with rolling peak demand charge and one month billing periods, $S_n^{\max}$ will be the peak demand recorded during the past billing period to ensure that the peak demand charge during the month under study is equal or higher than the charge corresponding to the previous peak demand by (30). If during the month under study, the optimal peak demand increases, and $S_n^{\max}$ will be updated accordingly for the following month, as also detailed in Fig. 2. In retail tariffs without rolling peak demand, $S_n^{\max}$ is set to be zero.

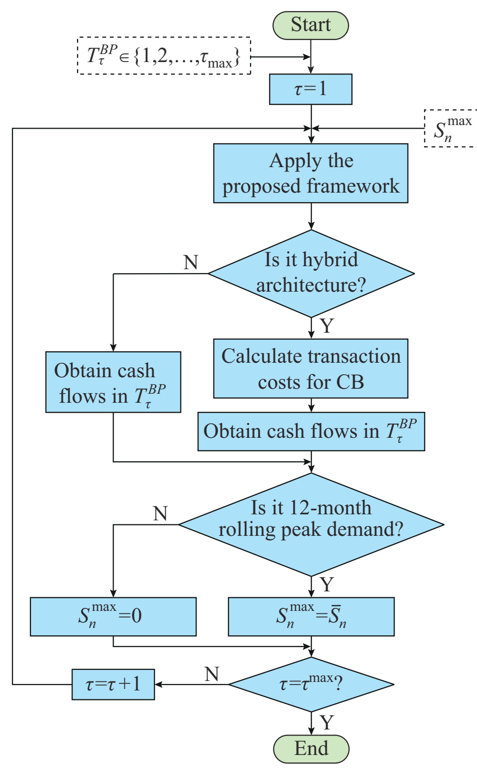

Fig. 2. Flow chart for deployment of proposed framework to obtain annual revenues in different architectures.

F. Deployment of Proposed Framework

The proposed framework is deployed using the logic presented in Fig. 2 to obtain the CB annual revenues. Each year has a set of billing periods, which are from 1 to $\tau^{\max}$. The process starts with the first billing period, and the proposed framework governs the CB operation during the billing period, according to the input data as presented in Fig. 2. Once the optimization in the proposed framework is finished, cash flows can be obtained. With a proposed hybrid architecture, the transaction costs are calculated to avoid double counting of energy from the CB between the gate meter and the child meter, and the host site remains playing a "net-zero sum" actor in terms of energy costs from the retail tariff. Additionally, if the peak demand charge is based on a rolling peak demand, the peak demand during that billing period is saved and introduced as an input during the following billing period, otherwise $S_n^{\max}=0$. The process continues for all billing periods to obtain the annual cash flows from the CB operation.

IV. Case Study

This section presents the case study to demonstrate the potential of the proposed framework.

A. 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-min granularity. The peak demand of this building is 120 kW, with an annual net energy consumption equaling to about 350 MWh. Additionally, the host site has a 85 kW PV system.

B. CB Data

The impact of different sizes of CB will be studied. The maximum CB charging/discharging power keeps constant and is equal to 100 kW, while various battery durations are tested, i.e., 100 kWh, 200 kWh, 400 kWh, 800 kWh, and 1600 kWh. All the different sizes are assumed to follow the Tesla Powerwall specifications and warranty requirements [34]. This entails that energy throughput during a billing period is calculated considering one cycle per day ($N_b=1$), so the battery warranty is not breached, guaranteeing a 10-year lifetime. The CB investment costs to assess its economic feasibility are obtained from [36], which details different investment costs as the CB duration increases (1-hour duration: 775 $/kWh; 2-hour duration: 400 $/kWh; 4-hour duration: 405 $/kWh). Annual maintenance costs are assumed to be equal to 8 $/kWh [37].

C. Market Data

Historical market data in Victoria, Australia from 2010 to 2022 obtained with NEOexpress [38] display distinct market conditions. Three parameters impacting the CB economic feasibility are identified through prescreening analysis: ① annual average wholesale market price; ② annual wholesale market price volatility measured as the standard deviation of the prices throughout the year; and ③ annual average contingency FCAS prices. Therefore, four distinct years are selected, as presented in Table I, to analyze the techno-economic operation of the CB under different market conditions.

TABLE I
HISTORICAL MARKET DATA IN VICTORIA, AUSTRALIA

Year	Wholesale market price ($)		Annual average contingency FCAS price ($)
	Annual average	Volatility	
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

Network DR data are obtained from a DN operator cost prediction for non-network solutions [27], as well as previously reported data in [28]. DR capacity must be committed during January and February, with a price equaling to 26 $/kW, while DR delivery price is equal to 7.5 $/kWh. A single DR event is assumed to be required at 17:30 for 90 min (hence, $\bar{\zeta}^{DR,delv}=6$), based on a DR event in Victoria, Australia on January 31, 2022 [39].

D. Retail Tariff Data

Retail tariffs are comprised of two main components, i.e., energy market and network components, as discussed in Section II-B. Table II presents the retail tariffs of the host site under study, highlighting the energy market and network components with the total energy cost (in the peak usage and off-peak usage terms) being the sum of the energy and network components. Moreover, two potential options for the network component of the retail tariff will be analyzed to understand which conditions are more favorable for the CB to co-optimize BTM and FOM value streams in the proposed hybrid architecture. The two potential options can be found in the local DN operator pricing proposal [40], and the different tariff terms are presented in Table II. Importantly, medium business tariff (CMG tariff) charges peak demand monthly, with two distinct prices for summer and winter. In large business tariff (CLLVT1 tariff), a 12-month rolling peak demand is charged monthly. The 12-month rolling peak demand is the highest demand of the customer in the last 12 months. It must be noted that according to [40], peak demand charges only apply to the peak demand between 10:00 and 18:00. In addition to the two potential options for the network component, one energy market component is considered, which is comprised of usage charges and feed-in tariff. And the feed-in tariff is the price the host site is paid for its exports. Finally, peak usage occurs between 08:00 to 20:00, whereas the rest of the day corresponds to off-peak usage.

TABLE II
RETAIL TARIFFS UNDER STUDY

Tariff	Peak usage (cent/kWh)	Off-peak usage (cent/kWh)	Feed-in tariff (cent/kWh)	Peak demand in summer ($/kVA)	Peak demand in winter ($/kVA)	12-month rolling peak demand ($/kVA)
CMG	5.20	5.20	N/A	15.75	5.33	N/A
CLLVT1	3.60	2.56	N/A	N/A	N/A	12.12
Energy market	7.12	5.75	4.9	N/A	N/A	N/A

V. Results and Discussion

This section presents the results and discussion of the proposed framework for the selected case study.

A. Architecture Comparison

The proposed hybrid architecture and the proposed framework allow to quantify the benefits from co-optimizing BTM and FOM value streams, as opposed to only optimizing BTM or FOM value streams. The results in Fig. 3 present a comparison of the value stream breakdown of the same system (a 100 kW/200 kWh CB during the year 2019 using the CLLVT1 tariff) with the three different architectures under study. The objective of this work is to understand the potential benefits of co-optimization in the proposed hybrid architecture to discern if this is a suitable option for CB implementation.

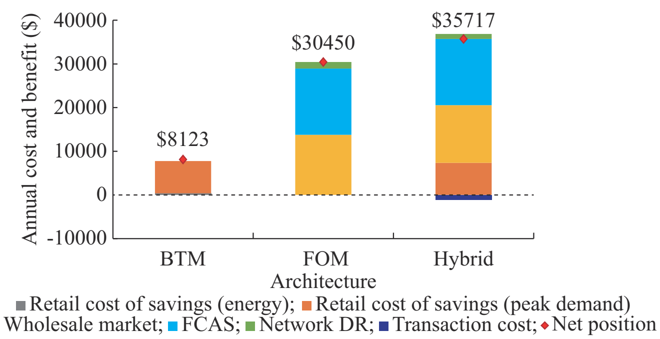

Fig. 3. Annual value stream breakdown for three architectures.

The BTM architecture displays that given the retail tariff selected (with energy and peak demand costs), most of the revenues from BTM value streams come from shaving the peak demand of the host site and reducing the subsequent costs. The limited volatility in the energy component of the retail tariff results in limited revenues from energy arbitrage.

The FOM architecture, allowing the CB to participate in wholesale energy market arbitrage, contingency FCAS, and network DR, significantly increases the CB revenues with respect to the BTM architecture, as displayed in Fig. 3. Most of the revenues arise from the wholesale market and FCAS participation, with similar share of the annual revenues (45% and 50% of the annual revenues, respectively) while network DR results in significantly less revenues (5% of the annual revenues).

In the proposed hybrid architecture, the CB is accessing both FOM value streams, i. e., wholesale market arbitrage, FCAS participation, and network DR, and BTM value streams, i. e., peak demand cost reduction. Accessing both FOM and BTM value streams results in some additional costs (as shown by the transaction costs in Fig. 3) to ensure the host site is a "net-zero sum actor" in terms of its retail energy costs. Despite these additional costs, the net position of the CB is significantly improved with respect to the BTM and FOM architectures, as the CB can successfully co-optimize system-level market participation and peak demand charge reduction, increasing the benefits with respect to both FOM and BTM value streams, and hence improving the potential CB economic feasibility.

The different price signals the CB responds to in the various architectures result in different CB dispatch, as demonstrated by Fig. 4. During this day, wholesale energy market prices are volatile with the CB charging and discharging to accrue significant revenues in FOM and the proposed hybrid architectures. Nevertheless, the CB significantly reduces its charging in the proposed hybrid architecture when compared with the FOM architecture during the time periods (from 10:00 to 18:00) in which peak demand charges apply. The CB dispatch in the BTM architecture significantly differs from that in the other two architectures, as the CB is providing arbitrage by discharging during the peak usage period (from 08: 00 to 20:00) of retail tariff.

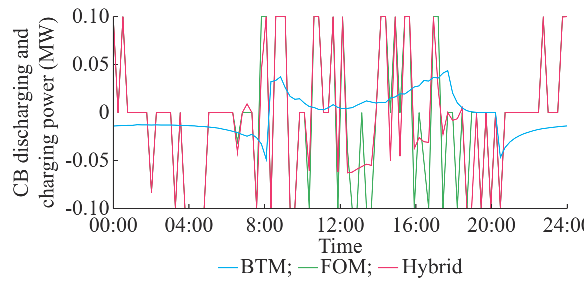

Fig. 4. CB dispatch on December 30th, 2019, in different architectures.

In addition to the active power response of the CB, the peak demand charge reduction, which is function of apparent power, results in a level of CB reactive power compensation, as detailed in Table III, in both BTM and proposed hybrid architectures. In the FOM architecture, the CB is not economically incentivized to inject/absorb any reactive power. As expected, the reactive power compensation in the BTM architecture is higher than that in the proposed hybrid architecture. Because when prices are high and volatile, the CB uses its full converter rating for discharge, as can be observed in Fig. 4. Besides, in the BTM architecture, with less volatile prices, the CB capabilities can be further utilized for reactive power compensation, in addition to prioritize discharging during the time of peak demand (from 10: 00 to 18:00).

TABLE III
Total CB Reactive Power Compensation in 2019

Architecture	CB reactive power compensation (MVArh)
BTM	32.28
FOM	0
Hybrid	30.23

B. Co-optimization Trade-offs of BTM and FOM

When co-optimizing BTM and FOM value streams in the proposed hybrid architecture, the total benefits are higher than those in the BTM or FOM architecture, as shown in Fig. 3. However, trade-offs arise. In the proposed hybrid architecture, the CB ability to participate in system-level markets (and subsequently accrue revenues) is reduced when compared with the FOM architecture, as it is also aiming to minimize the peak demand costs of the host site. At the same time, when system-level market prices are high, the CB may prioritize market participation over shaving the peak demand, reducing the BTM benefits with respect to the BTM architecture. In Fig. 5, a statistical analysis is presented, displaying the distribution of the co-optimization trade-offs for BTM and FOM value streams in the proposed hybrid architecture for different years of market prices and battery sizes with the CLLVT1 tariff. Note that the colored dots represent the data points making up the statistical distribution in the box-and-whiskers plot. BTM benefits are reduced on an average of 12.5% in the proposed hybrid architecture when compared with those in the BTM architecture. Besides, FOM benefits are reduced on an average of 4% in the proposed hybrid architecture with respect to those in the FOM architecture.

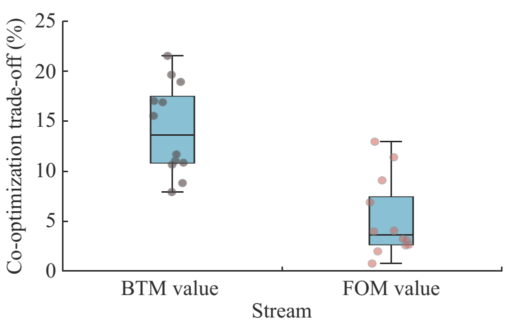

Fig. 5. Co-optimization trade-off for BTM and FOM value streams.

Although the individual BTM and FOM value streams are reduced in the proposed hybrid architecture, the co-optimization results in increased total annual benefits when compared with BTM and FOM architectures, as already mentioned and further demonstrated in Fig. 6. In Fig. 6, the statistical analysis is grouped by years 2010 and 2011 as well as 2017 and 2019, as there are striking differences in the relative annual benefit that the proposed hybrid architecture provides with respect to BTM and FOM architectures. Years 2010 and 2011 are characterized by lower FCAS and wholesale energy market prices. In these cases, the proposed hybrid architecture achieves a similar relative increase of annual benefits with respect to both FOM and BTM architectures. However, in 2017 and 2019, with more favorable system-level market conditions for the CB to accrue significant revenues, the relative increase of benefits with respect to the BTM architecture is significant, reaching an average of 360%, whereas the relative increase of benefits with respect to FOM architecture is 20%. This indicates that with high and volatile system-level market prices, the relative benefits of accessing BTM benefits as well as FOM benefits are not as significant. However, with lower and less volatile system-level market prices, the proposed hybrid architecture significantly increases the CB economic position. Overall, being able to co-optimize FOM and BTM benefits in the proposed hybrid architecture is beneficial. Co-optimization does not significantly reduce the CB ability to access FOM value streams when significant revenues can be accrued. However, if system-level market prices are low and less volatile, it ensures a steady source of revenues from BTM value streams.

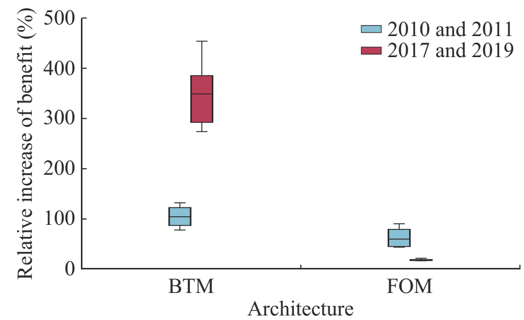

Fig. 6. Relative increase of benefits in proposed hybrid architecture.

C. Co-optimization with Different Tariffs

The previous results have assumed that the network component of the retail tariff is defined by CLLVT1 in Table II. Here, we further study two potential structures for the network component to analyze their impacts on the co-optimization of BTM and FOM value streams. The main difference is the structure of peak demand charges. Peak demand charges of CMG tariff are a function of the highest demand each month. CLLVT1 tariff, on the other hand, considers the highest demand in the last 12 months to calculate peak demand charges, i.e., 12-month rolling peak demand.

Figure 7 presents the benefit reduction in BTM and FOM value streams with the proposed hybrid architecture and the CMG tariff when compared with CLLVT1 tariff. With a rolling peak demand charge in CLLVT1, the CB has some additional flexibility to only reduce peak demand during critical instances while participating in system-level markets. However, with a peak demand charge based on monthly peak demand, the CB has less flexibility for the co-optimization of BTM and FOM value streams. The results in Fig. 7 indicate that the CB mainly prioritizes the participation in system-level markets rather than BTM benefits, as the reduction in benefits from FOM value streams is around 5%. Overall, these results highlight that the structure of the network components in the retail tariff has significant impact on the ability of the proposed hybrid architecture to co-optimize BTM and FOM value streams. More flexible peak demand structure results in improved co-optimization. These results provide quantifiable evidence that there is value in selecting retail tariffs in which peak demand charge provides more flexibility for co-optimization.

Moreover, without perfect foresight, the benefit reduction presented in Fig. 7 may be further accentuated. First, the monthly peak demand requires updating the control signal for peak demand reduction each month. Otherwise, the peak demand reduction achieved each month will significantly differ with the theoretical optimal reduction. Additionally, by having to reduce peak demand on a monthly basis, it is more likely that two opposing circumstances take place: ① more instances in which the control signal overrides CB market participation for peak demand reduction or ② lower peak demand reduction to not sacrifice revenues from market participation. With a 12-month rolling peak demand, significant peak demand reduction can be performed by only controlling the CB in a few critical instances within a year.

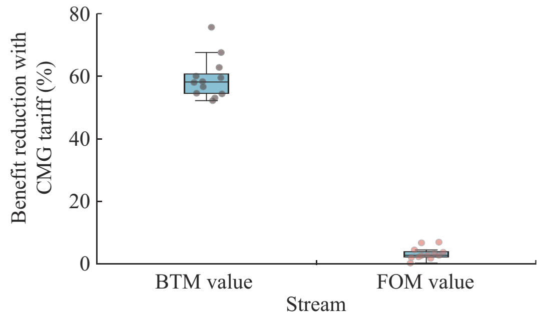

Fig. 7. Benefit reduction in BTM and FOM value streams with proposed hybrid architecture and CMG tariff when compared with CLLVT1 tariff.

D. CB Energy to Power Ratio and Economic Feasibility

The proposed framework is deployed in different years for the three architectures given various CB energy storage durations with CLLVT1 tariff, which provides insights on battery sizing. Figure 8 provides the total annual benefits of the CB as its duration increases, i. e., in 2017 of Fig. 8(a) and in 2011 of Fig. 8(b). Year 2017 is selected as the best-case scenario and 2011 is selected as the worst-case scenario, i. e., when the economic net position of CB from market participation is the best (2017) and the worst (2011), respectively. The results in Fig. 8 show that for all architectures and both years, increasing CB durations up to 4 hours results in increased benefits, with an almost linear evolution. For CB durations longer than 4 hours, the increase in benefits starts showing a decreasing rate of improvement as the CB duration increases, with saturation occurring around the 8-hour case.

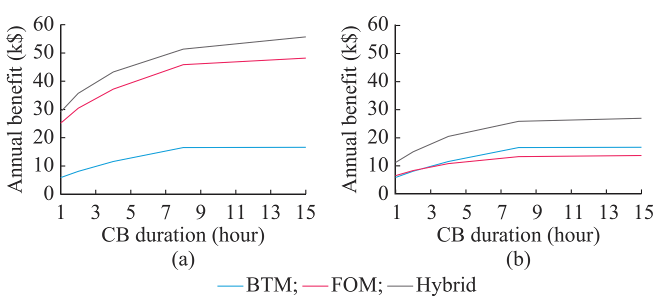

Fig. 8. Annual benefits of CB for different CB durations. (a) 2017. (b) 2011.

While the results in Fig. 8 display no significant differences in the impact of CB duration between the three different architectures, once a net present value (NPV) analysis is performed, CB duration shows distinct evolution in the proposed hybrid architecture when compared with FOM and BTM architectures. The NPV analysis is performed, assuming that during the ten years of analysis, system-level markets are equivalent to 2017 and 2011, respectively, as the best-case and worst-case scenarios. The results in Fig. 9 present a NPV analysis for different CB durations up to 4 hours (prior to the saturation of benefits observed in Fig. 8). While the maximum NPV in the BTM and FOM architectures takes place for a 1-hour CB duration in both scenarios, the maximum NPV in the proposed hybrid architecture takes place for a 2-hour CB duration, in both scenarios as well. This indicates that higher CB duration is preferrable when performing co-optimization of BTM and FOM value streams, even in strikingly different market conditions.

The economic feasibility of a CB project depends, in general, on various aspects, e. g., technology costs, regulatory framework, retail tariffs, and system-level market prices. System-level market prices are highly uncertain, but critical for the economic feasibility of CB projects. Importantly, as mentioned earlier, in the proposed hybrid architecture, by co-optimizing BTM and FOM value streams, the impact of uncertain system-level market prices on economic feasibility can be mitigated, while still allowing the CB to accrue significant revenues via market participation. While the NPV analysis displayed in Fig. 9 is only illustrative (forecasts of ever-changing system-level market prices across the battery's lifetime would be needed to make financial decisions on the CB), it clearly demonstrates the potential of the proposed hybrid architecture to hedge the risks of uncertain system-level market prices.

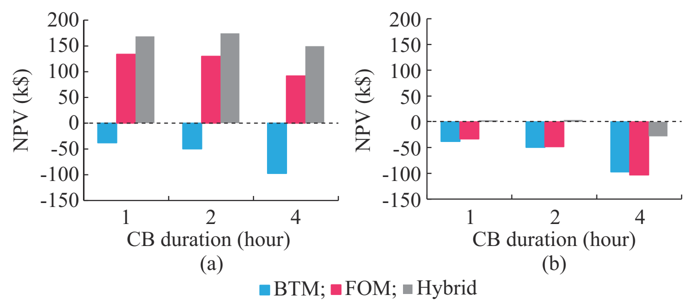

Fig. 9. NPV analysis of CB in three architectures. (a) Best-case scenario. (b) Worst-case scenario.

In fact, Fig. 9 shows that while the BTM architecture is not impacted by system-level market prices, the CB is not economically feasible. With favorable market conditions, i.e., best-case scenario using 2017 prices, the FOM architecture provides positive NPVs. However, with unfavorable market conditions, i. e., worst-case scenario using 2011 prices, the FOM architecture presents negative NPVs, which are equivalent to those of the BTM architecture. In contrast, the proposed hybrid architecture shows positive NPVs even in the worst-case scenario (for 1-hour and 2-hour CB duration), and higher NPVs than those of the FOM architecture in the best-case scenario. In summary, Fig. 9 highlights that the proposed hybrid architecture decreases the impact of unfavorable market conditions on the CB economic feasibility, while still allowing the CB to accrue significant revenues if/when favorable market conditions arise, providing significant risk-hedging benefits for the CB economic feasibility.

VI. Conclusion

This paper proposes a hybrid architecture and a framework that enable the co-optimization of BTM and FOM value streams considering consumers' aversion to face the price volatility of system-level markets. With the proposed hybrid architecture, a significant advancement is achieved, as existing literature has proposed frameworks that only allow CB to access BTM or FOM value streams. In this sense, the proposed hybrid architecture and proposed framework allow the CB to participate in system-level markets, while reducing the peak demand charge of host sites, which is a crucial value stream in BTM architecture. Moreover, the proposed framework is architecture-agnostic, allowing a seamlessly performance comparison of BTM, FOM, and the proposed hybrid architectures.

Through a realistic case study of a host site located in Victoria, Australia, it has been demonstrated that the CB can effectively co-optimize BTM and FOM value streams. Slight trade-offs arise from the co-optimization, when compared with BTM and FOM architectures that only access local and system-level benefits, respectively. Despite these slight trade-offs, there is an increase in the annual benefits of the CB. Moreover, the CB revenues are less dependent on uncertain system-level market prices, improving its economic feasibility and hedging against the risk of low market prices. In terms of parameters that affect the co-optimization, it was found that 2-hour duration CB show the highest NPV when co-optimizing BTM and FOM value streams, even under different system-level market conditions. Conversely, when only BTM or FOM value streams are accessed, 1-hour duration CB shows the highest NPV, highlighting co-optimization benefits from longer duration CB. Additionally, in all architectures, CBs beyond 4-hour duration display a saturation in the accrued revenues. It should be noted that the analysis of CB duration may be affected by the attributes of different markets, and in various markets around the world, revenue saturation may occur for lower/higher CB durations. Flexibility in the peak demand charge is also important for the co-optimization. In this sense, network tariffs that charge peak demand in 12-month rolling basis offer more flexibility for the CB to co-optimize FOM value streams while reducing peak demand during the critical instances of the year. Besides, charges based on monthly peak demand require the CB to shave peaks monthly, resulting in lower savings, as system-level market participation is generally prioritized in the co-optimization. Overall, this work has demonstrated that CB can be leveraged to provide both local and system benefits and price uncertainty risk hedge, both of which are critical paths towards economic feasibility. Future work will address relevant issues on the CB deployment, including regulatory issues as well as other operational parameters that may affect their viability, such as uncertainty in load and generation and online testing demonstrating the co-optimization potential of CB.

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