Comprehensive techno-economic modelling of alternative/complementary storage options

Milestone Report 1: 20/01/2025

Report for C4NET

1.1 Project Consortium

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1.2 Executive Summary

This report explores various distribution-level energy storage technologies gaining traction in Australia, including household batteries, community batteries, electric vehicles, building fabric thermal storage and domestic hot water systems.

Household batteries play a crucial role in enhancing the economic viability of rooftop PV systems by enabling energy storage for later use and promoting self-consumption. Research has shown additional benefits that may come from these systems: peak demand reduction, local voltage control and transmission and distribution network investment deferral. They can be either independent or coordinated by third parties in Virtual Power Plants (VPPs), offering other significant benefits like market participation and enhanced system visibility for distributed energy resources (DER). As the NEM's storage demand grows, the uptake of household batteries will need to increase substantially to meet future energy needs, particularly as part of coordinated VPPs for grid support.

Community batteries (CB), also known as neighbourhood batteries (NB), offer another flexible, cost-effective solution for balancing local energy generation and demand, somehow placed between household batteries and grid-scale storage. By leveraging demand and generation diversity, CBs increase solar hosting capacity. Various configurations, including behind-the-meter (BTM), front-of-the-meter (FOM) and hybrid models, allow CBs to access multiple value streams, with hybrid models offering the most economic potential. Ownership models (local government, retailers or network operators) need careful consideration, with reduced local energy transport prices required to incentivize local energy exchange.

Electric Vehicles (EV) storage differs from traditional battery storage due to its variable power and energy capacity availability, impacted by charger type, and the proportion of EV connected to the grid, which depends mostly on consumer behaviour. Chargers range from unidirectional ones to advanced bi-directional ones that enable vehicle-to-grid (V2G) integration. V2G allows EV to discharge energy back to the grid, offering benefits like grid resilience, frequency control, and cost savings. On the other hand, EV storage availability depends on battery size (larger batteries requiring fewer charges), driving habits and charging frequency, which will be highly impact by consumer preferences. Integrating V2G infrastructure could enhance grid flexibility and unlock additional storage capacity.

Building fabric-related thermal storage enables building to store thermal energy for short periods, reducing heating and cooling needs. This storage can be utilized in two ways. First, as demand response (DR), by switching off heating or cooling devices, leveraging the building's thermal inertia. Second, through demand shifting pre-cooling buildings during hot weather or pre-heating them during cold weather. During hot weather, buildings may be pre-cooled, storing cooling capacity that is gradually released as temperatures rise, reducing HVAC demand. In cold weather, buildings may be pre-heated, storing thermal energy that is released as the temperature drops. The effectiveness of this strategy depends on building insulation, size and external conditions (weather and occupancy), with well-insulated buildings maintaining comfort for longer without active heating and cooling. This can be modelled as a load-shifting approach to optimize energy use.

Domestic Hot Water (DHW) storage systems include technologies like heat pumps solar water heaters and electric heaters. Similarly to the building fabric-related storage, heat pumps and electric heaters can also use their storage capabilities to provide DR. Furthermore, instead of being simply turned on/off, some modern DHW tanks can also change their power consumption by fixed increment, giving this device more flexible DR capabilities. Besides, heat pumps and electric heaters can also be dispatch during off-peak hours to help managing the demand by heating overnight and can be adapted to shift heating to peak renewable generation times, to store excess PV energy. This approach might be more cost-effective than a battery for homes already equipped with electric DHW tanks and may help to stabilize network voltages. DHW is also predictable and temperature-dependent, providing useful data for network operations.

The growing adoption of these energy storage technologies offers significant potential to enhance energy efficiency and reduce costs in Australia. By leveraging the synergies between them, system operators could better manage energy demand, support renewable integration and improve the assessment of investment options to address future energy challenges.

This report establishes a foundation for integrating these storage options into mathematical models, crucial for understanding their individual capabilities, synergies, and grid interactions. The next step is to develop accurate models that capture these diverse storage capabilities, providing valuable insights into the challenges and opportunities of distributed storage deployment.

1.3 Glossary of Terms / Abbreviations

AEMO	Australian Energy Market Operator
ISP	Integrated System Planning
CER	Consumer Energy Resources
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
EV	Electric Vehicles
DR	Demand Response
TES	Thermal Energy Storage
DHW	Domestic Hot Water
LV	Low Voltage
V2G	Vehicle-to-Grid

1.4 Table of Contents

2 Project Overview

This report corresponds to *Milestone 1*, a literature review of distribution network storage for the Work Package 2.10 (WP2.10), *"Comprehensive techno-economic modelling of alternative/complementary storage options"*. WP2.10 will ultimately assess the interactions of different storage options to determine how they can enhance system flexibility and support optimal distribution network operation and planning.

2.1 Background

As Australia transitions towards a cleaner, more sustainable energy future, storage systems play an increasingly important role in the energy system. Storage systems provide economic benefits such as energy arbitrage by storing electricity from periods of low-cost production (often coinciding with high renewable generation) and releasing it during higher cost hours (often coinciding with peak demand periods). This energy arbitrage thus help reduce energy curtailment while improving system reliability. The rapid expansion of renewable energy sources is increasing the price differential between low-cost and high-cost periods, which makes storage solutions increasingly attractive to stakeholders, driving an accelerated deployment of storage across all grid levels, from transmission to distribution networks.

In Australia, the Australian Energy Market Operator (AEMO) projects that distribution-connected storage will experience the highest long-term penetration, contributing several gigawatts of capacity to the grid, as shown in Figure 1. However, current projections often overlook the potential contributions of emerging storage technologies such as electric vehicles (EVs) and thermal storage devices, including building fabric-related thermal storage in buildings, and domestic hot water storage in tanks.

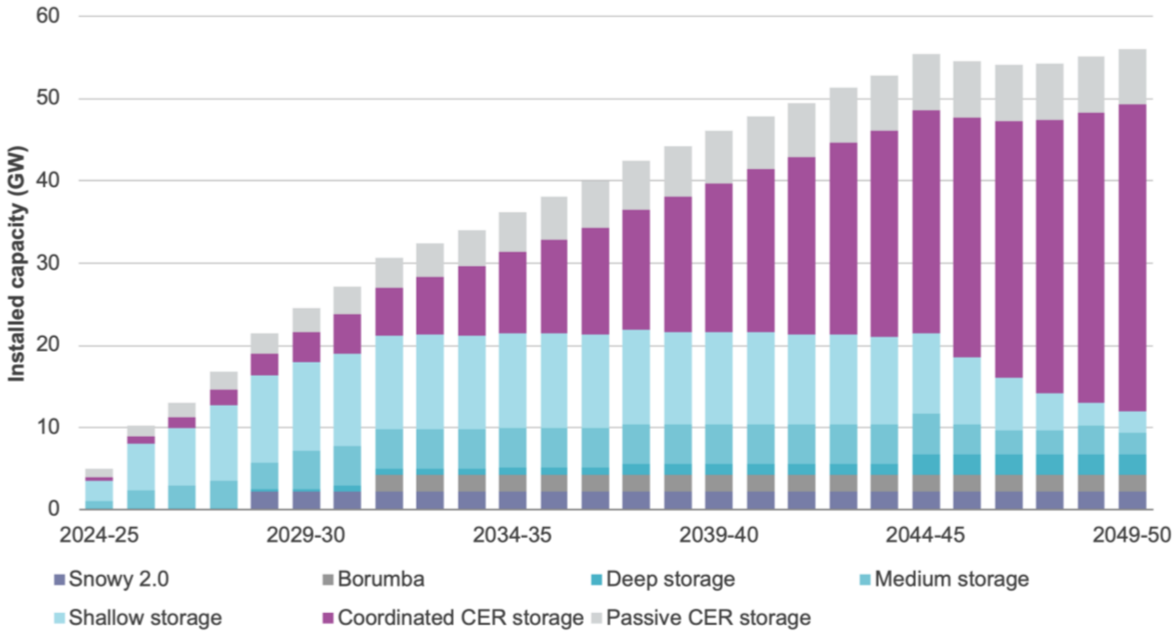

Figure 1 Forecasts of storage Installed capacity in the ISP, NEM (2024-25 to 2049-50) [1]

The orchestration of these diverse storage technologies is fundamental to enable greater integration of renewable energy sources. In distribution networks, these storage technologies can help reduce network congestion, lower peak demand, and postpone costly infrastructure investments. In the long term, distributed storage will be crucial in the transition to a new, more flexible, power system where energy can flow both ways between transmission and distribution networks.

This report provides a comprehensive review of storage options available at the distribution level, examining their potential value within Australia's evolving energy system and exploring strategies for their effective integration into power system models. The report will also examine the current state of these technologies in Australia and offer insights into future opportunities for the coordinated operation of these distributed storage resources.

2.2 Aims and Objectives

WP2.10 "Comprehensive modelling of alternative/complementary storage options", as part of C4NET Enhanced Systems Planning (ESP), aims to:

- Provide a techno-economic assessment of the benefits brought by multiple storage options (household and community batteries, EV storage and thermal storage) considering different sensitivities.
- Assess the impact of various storage model and scenario parameters on the networks, further informing scenario developments of different stakeholders (storage support to mitigate the impact of 100% solar penetration, storage support for different sizes and mix of constrained/unconstrained export/import scenarios, cumulative impact of EV penetration.)

WP2.10 should provide a better understanding of the role of different storage options in distribution networks. Providing insights to the Victorian and Australian government about potential cost savings through the effective utilization of storage resources.

2.3 Key Milestones

The key milestones of this work package, and the corresponding contents are further detailed bellow.

Milestone 1: Literature Review (January 2025)

Report with overview of different storage options (household batteries, electric vehicles, thermal storage, community batteries) at distribution level

Milestone 2: Modelling and techno-economic assessment

A detailed presentation highlighting the different modelling approaches employed to assess the optimal mix of storage options in different scenarios.

Milestone 3: Evaluation of different flexibility provision options

A detailed presentation showcasing multi-parametric aggregated profiles to inform planning at different level, carried out with a bottom-up approach.

Milestone 4: Final Report

A final report presenting the findings of WP 2.10, including a summary of inputs, assumptions, as well as results from case studies.

3 Overview of energy storage options

Energy storage technologies play a critical role in enhancing the efficiency and reliability of power systems. By storing energy during periods of low demand and releasing it during peak demand, these technologies help to balance supply and demand, reduce reliance on fossil fuels, and integrate renewable energy sources more effectively.

There are several primary types of energy storage [2] [3] [4]:

1. Mechanical: Mechanical energy may be stored as the kinetic energy (e.g., Flywheels), as compressed energy in elastic materials or gases (e.g., compressed air storage), or the most extended one as potential energy in elevated object (e.g. pump storage),
2. Electrical: Electrical energy is stored with devices capable of storing an electric charge such as ultracapacitors. This technology offers high short charging and discharging times, fast response and high efficiency.
3. Chemical: Chemical energy storage involves storing energy as chemical compounds. This is achieved through chemical reactions to produce hydrogen, ammonia or synthetic gases. Chemical storage offers higher energy density compared to other storage types, making it suitable for long term storage and transportation.
4. Electrochemical: Energy may be stored in systems composed of one or more chemical compounds that release or absorb energy. The most familiar electrochemical device is the battery. Energy stored in batteries is frequently referred to as electrochemical energy because chemical reactions in the battery are caused by electrical energy and subsequently produce electrical energy.
5. Thermal energy storage (TES): Thermal energy may be stored by raising or lowering the temperature (sensible heat), changing the phase of a substance (latent heat), or both. Common applications include space heating/cooling and hot water production.

Various industrial and residential storage applications can be categorized based on their discharge duration and capacity range, as illustrated in Figure 2. This figure demonstrates the diverse range of storage technologies and their potential applications.

Chemical storage, particularly hydrogen-based systems, may have the potential of shifting energy across weeks or seasons [5]. Pumped hydro storage and batteries can shift energy from hours to days or weeks, depending on the scale of the project. Thermal storage options like liquid air energy storage (LAES) and molten salt can store energy at the megawatt scale for hours to days [6]. Supercapacitors and flywheels, on the other hand, are designed for rapid energy delivery and can release stored energy within seconds or minutes.

This report focuses on distribution-level storage, which involves thermal and electrochemical devices as batteries. Thermal storage at this level includes building fabric-related thermal storage (e.g., pre-cooling or pre-heating in buildings) and domestic hot water storage. Electrochemical storage options include batteries in residential/community systems and electric vehicles.

Distribution-level storage in the same distribution network typically operates over durations of minutes to hours and at power capacities ranging from kilowatt to megawatt. By orchestration of the distributed storage available in several distribution networks for transmission-level purposes, it is expected that the storage connected within distribution networks could reach values around gigawatts/gigawatthours.

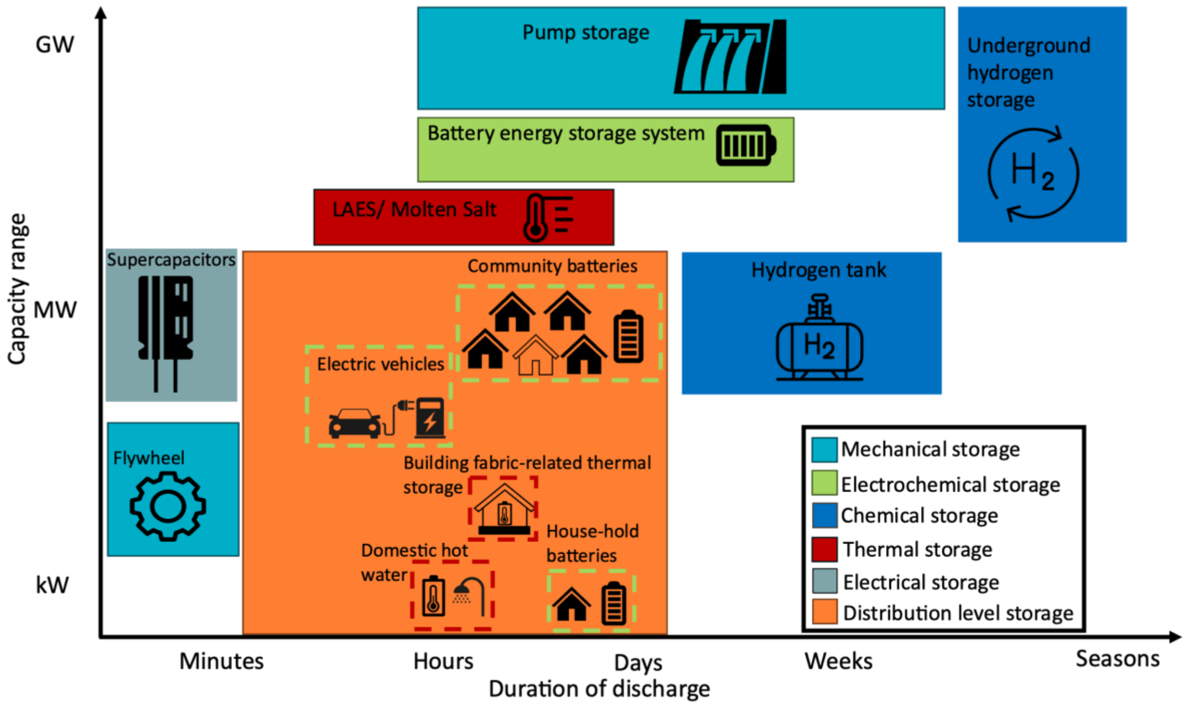

Figure 2 Type of storage classified with different duration and capacity

4 Distribution-level storage options

The primary storage options at the distribution level encompass five technologies: household batteries, community batteries, electric vehicles (EVs), building thermal storage, and domestic hot water storage. This chapter provides an overview of each storage option, exploring their storage value and their projections in the Australian system.

4.1 Battery based storage options

4.1.1 Household batteries

Household batteries enhance the economic viability of residential PV systems by promoting self-consumption and reducing reliance on the grid. Integrating a household battery enables homeowners to store excess solar energy for later use during periods of high demand or low solar irradiance.

The operation of these devices can be modelled by equations (1)-(8). The battery charge and discharge powers are defined as positive variables $p^{ch}(t)$ and

$p^{dh}(t)$ with the maximum charge and discharge power $\overline{p^{ch}}$, $\overline{p^{dh}}$ and the binary variables $\theta^{ch}(t)$ and $\theta^{dh}(t)$, and are constrained in (2) to avoid simultaneous charging and discharging of the battery. The net output of the battery is defined in (4). Equation (5) sets the upper and lower bounds of the normalized battery state-of-charge (SOC) and equations (6)-(7) set the initial and final SOC. The energy balance of the battery is modelled in (8), where E_b is the battery nameplate energy capacity and η_c/η_d the battery charge/discharge efficiencies. Finally, equation (9) describes customer's net import/export as function of the load demand $p^{load}(t)$ and the PV generation $p^{PV}(t)$.

$$0 \leq p^{ch}(t) \leq \overline{p^{ch}}\theta^{ch}(t) \tag{1}$$

$$0 \leq p^{dh}(t) \leq \overline{p^{dh}}\theta^{dh}(t) \tag{2}$$

$$\theta^{ch}(t) + \theta^{dh}(t) \leq 1 \tag{3}$$

$$p(t) = p^{ch}(t) - p^{dh}(t) \tag{4}$$

$$0 \leq x(t) \leq 1 \tag{5}$$

$$x(t_0) = x_0 \tag{6}$$

$$x(t_f) = x_f \tag{7}$$

$$E_b\big(x(t+1) - x(t)\big) = \left(\eta_c p^{ch}(t) - \frac{p^{dh}(t)}{\eta_d}\right)\Delta t \tag{8}$$

$$p^{net}(t) = p^{load}(t) - p^{PV}(t) + p(t) \tag{9}$$

Household batteries mostly use Lithium-Ion (Li-ion) technology. These batteries are characterised by their high roundtrip efficiency (around 90%) and long cycle and calendar lifetime (8000 full cycles and 20 years). A typical household battery in use in Australia is the Tesla Powerwall 2, a single-phase 5 kW/13.5 kWh household battery with a 90% efficiency [7], costing around $1150/kWh as of 2024 [8].

Extensive research has been conducted on the optimal sizing of household PV-household battery systems [9, 10, 11]. Household batteries can provide a reduction in peak demand at the local level and local voltage control [12] , which may lead to wider system benefits such as transmission/distribution network investment deferral [13]. Similarly, load shifting from household batteries may reduce the need for new utility scale generation and reduce power losses on the network [14].

Another crucial aspect of this small, distributed storage system is that they can either by coordinated by third-parties or operate independently of the network [14].

Controlled household batteries could have significant advantages compared to non-controlled household batteries [15]. One notable benefit of household batteries coordination through VPP is that it can provide distribution-level visibility in the NEM [16]. Having VPP operators share asset and fleet-level datasets might be highly valuable, offering insights that were previously inaccessible to the market operator. In addition to this, the centralised control inherent in VPP arrangements is valuable for both AEMO and network operators since it enables the provision of additional market services, such as Frequency Control Ancillary Services (FCAS) and allows aggregator to respond to emerging network and system-security requirements. Conversely, noncontrollable household batteries might exacerbate some issues such as reverse power flows [15]. Since household batteries default strategies typically prioritize storing as much excess PV generation as possible, household batteries may reach their full state of charge before peak PV generation periods, leading to excess power being fed back into the grid [17]. This reverse power flows across multiple sites may cause technical issues such as over-voltages and thermal congestion, particularly on low and medium voltage networks.

4.1.1.1 Household batteries in Australia

More than 250,000 household batteries were in operation in Australia in 2023. However, 3.7 million households in Australia have rooftop PV, meaning less than 1 in 14 households in Australia have a storage system installed with their PV system. Those batteries amount to 0.2 GW of storage, compared to 3 GW of storage capacity across Australia, all technologies considered. However, current forecast from the ISP show that the NEM will need at least 32 GW/522 GWh of storage capacity in 2034-35 and 56 GW/660 GWh in 2049-2050 – see Figure 1 and [18].

Figure 3 shows the maximum charging/discharging power for different years in Victoria. This figure is made based on the demand trace from the ISP [18]. Charging demand from household batteries is expected to grow nearly sevenfold between 2025 and 2052, reflecting the anticipated rise in household battery installation to accommodate for the growing increase in distributed generation in Australia and illustrating the additional storage capacity that those devices represent.

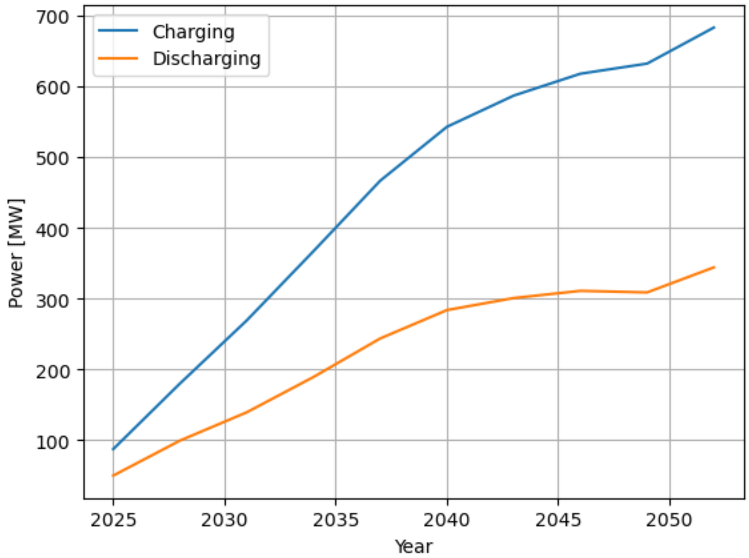

Figure 3 Maximum charging/discharging aggregated power for household batteries in Victoria based on data from [18]

AEMO forecasts the prominent role of consumer-owned resources (CER) in the future Australian power systems, if net zero is to be achieved by 2050. Note that consumer-owned storage refers to behind-the-meter (BTM) storage including EVs. Coordinated CER storage is managed as part of a VPP, while passive CER storage is not. According to AEMO, this will require a massive increase in the uptake of household batteries in Australia. Households will also have to be willing to share their device and/or sell their excess electricity back to the grid for which governments will likely need to provide significant incentives. Finally, despite having substantial combined installed capacity, these household batteries might only provide electricity at maximum discharge for about two hours, resulting in limited combined energy capacity. Consequently, according to AEMO more extensive utility-scale storage solution would be needed to support renewable energy growth [18].

Controlled household batteries have been showcased in a range of projects across Australia. The CONSORT Bruny Island Battery Trial (2016-2019) [14], a pioneering initiative, explored the coordinated operation of 34 household batteries to provide peak demand reduction services. This coordinated approach resulted in improved batteries performance in reducing peak demand, leading to a roughly 33% reduction in costly diesel generation and providing economic benefits to both the electricity grid and participating households. Households received compensation for providing these services through a pricing mechanism developed during the trial.

Other VPP projects were investigating the coordination of household batteries for participation in multiple energy markets, like the AGL Virtual Power Plan Project [19], from 2017 to 2022. This project aggregated solar PV and household batteries over 1000 systems in Adelaide, SA. The VPP was used to participate in the wholesale and FCAS markets. It was the first project of this scale demonstrating that coordinated household batteries could provide value across a range of different markets.

An additional VPP trial is the Tesla VPP trial [16]. Following the installation of 3000 Tesla systems in SA with a goal of deploying up to 50,000 PV and Powerwall systems, the VPP has developed advanced software to manage the output of the systems to provide energy and contingency FCAS. In addition, coordinated household batteries have been trialled for provision of other services: voltage support through Volt-Var control via the Powerwall’s’ inverter, fast frequency response (FFR) and virtual inertia.

4.1.2 Community batteries

Community Batteries (CB),also known as neighbourhood batteries (NB), are flexible resources that have been proposed as an intermediate solution between household batteries systems and grid-scale batteries, for balancing local intermittent renewable energy generation and load demand in residential areas [20]. By charging during peak solar generation and discharging during periods of high community demand, CBs enhance the utilization of local renewable energy and contribute to grid stability, like household batteries. Community batteries mostly use Lithium-Ion (Li-ion) technology, with an efficiency of 88-90% and have a calendar lifetime of 10 years [21].

The social acceptance of community batteries was investigated in a series of end-user interviews [22, 23]. End-users expressed a strong preference towards ownership models where CBs were owned by local governments and run as a not-for-profit entity [23]. It was noticed that DNSP-owned projects encounter regulatory challenges, retailers-led models face consumer trust issues, and community-driven models face logistical obstacles [23]. Yet end-users expect these batteries to improve resilience and decarbonation, in addition to lowering the bills [22].

Existing literature demonstrates that CB represent a more cost-effective solution than private batteries for storing excess generation [24, 25, 26]. Indeed, leveraging the demand and generation diversity existing at community-level as well as economies of scale may decrease the total size of storage requirement, and per-kW investment costs [27]. In particular [28] shows that for a 10-homes community, using a CB may leads to a 37% reduction in operational cost compared to a household battery in a single home. Hence earlier research on CB primarily focused on optimal sizing [29] and location [30] of CB within a community. CB might be especially useful in urban areas, where resident may live in high-rise apartment buildings and therefore may not be able to install privately-owned batteries. Similarly for rural and remote communities, a CB might reduce the community's reliance on long distribution feeders, which is especially valuable in the face of extreme weather events that might threaten their energy supply. Note that operating the CB independently of the grid, would require higher battery costs, in terms of both hardware and control.

In addition, CB might simultaneously engage in various electricity markets, like wholesale energy market and Frequency Control Ancillary Services (FCAS) market [31]. Frequency Control Ancillary Services (FCAS) are categorized into two main groups: regulation FCAS and contingency FCAS. Regulation FCAS is responsible for continuously correcting minor frequency deviations, while contingency FCAS is employed to rectify major frequency deviations resulting from unexpected events or contingencies such as the loss of large a generator or load. Under the current Australian regulatory framework, DERs such CBs are only allowed to participate in contingency FCAS markets. Since most contingency FCAS revenues arise from availability rather than delivery [32] [32], leveraging idle CB capacity for contingency FCAS may boost CB revenues [31] as illustrated in Figure 4.

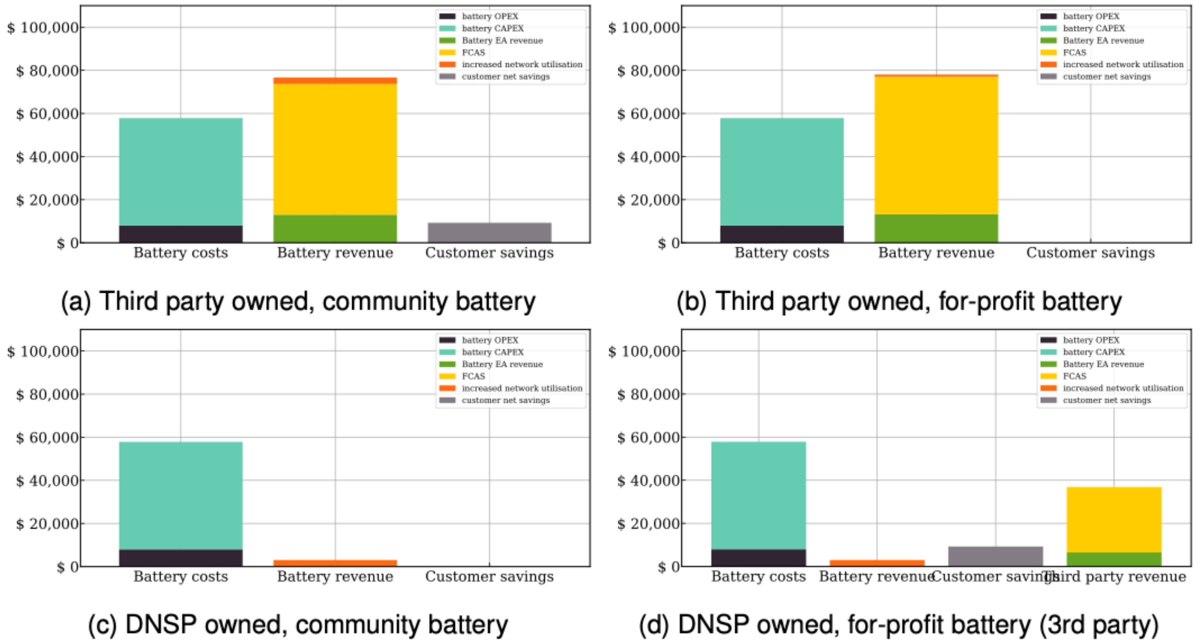

Figure 4 Costs and revenue for one year (2018) for the four models examined [33]

In the previous commercial setup, the CB operates directly in the markets and is labelled a front-of-meter (FOM) battery. However, alternative commercial configurations have been explored in the literature [31], as depicted in Figure 5, with each accessing distinct value streams. This becomes particularly relevant as "value stacking" emerges as a crucial strategy for enhancing the CBs economic feasibility.

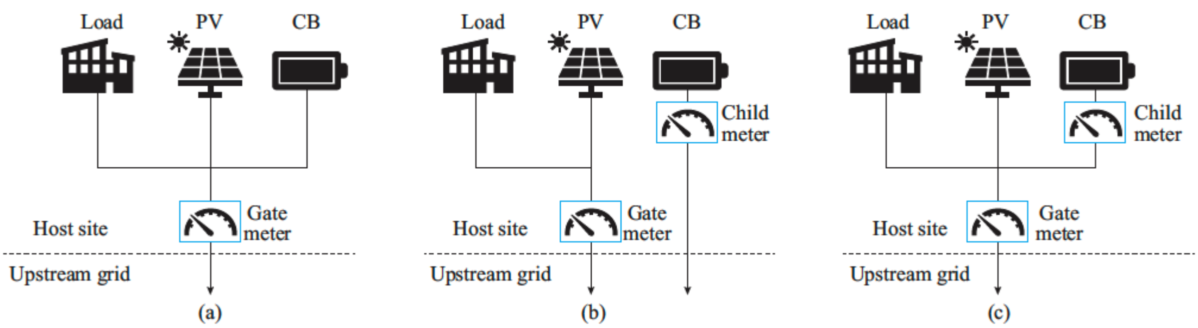

Figure 5 Community batteries architectures (a) Behind-the-meter (BTM), (b) front-of meter (FOM) and (c) hybrid architecture [31]

The BTM architecture is comprised of one single meter (the gate meter). In this architecture, all the resources downstream of the gate meter are coordinated. The CB can provide retail tariff arbitrage. In the FOM architecture CB and host site are operated independently. The CB is facing system-level markets through the child meter. The community's import/export are metered through a separate device and subjected to the retail market and network tariffs. In this architecture the CB cannot provide any BTM benefits to the community. The hybrid architecture, originally proposed in [31], allows the CB to access both FOM and BTM benefits. The gate meter measures the total energy import/export for the community, and the child meter measure the CB performance in different markets.

As illustrated in Figure 6 the BTM architecture's revenues could mainly come from shaving the host site's peak demand and reducing the associated costs. The FOM architecture's revenues mostly stems from wholesale market participation and contingency FCAS provision, as discussed earlier. Finally in the hybrid architecture both FOM and BTM value streams can be accessed, significantly increasing revenues accrued by the CB. Other services that a CB could provide include: backup power in case of an outage, network upgrade deferral, and congestion relief.

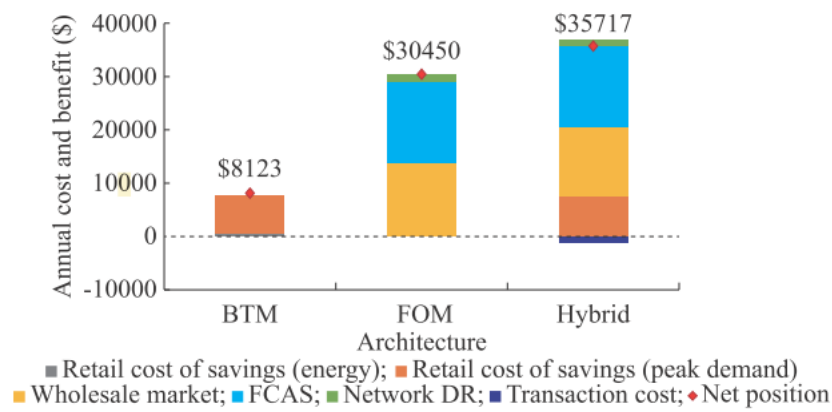

Figure 6 Annual value stream breakdown for the three architectures. CB is 100kW/200kWh using market data from 2019 and CCLLVT1 tariff [31]

In the National Electricity Market (NEM), regulation prevents DNSPs from directly buying and selling energy to customers [34]. This presents a significant challenge for DNSPs-owned CBs in the NEM as they are excluded from the wholesale and FCAS markets. One potential solution explored in the networked-owned for profit battery model is leasing the CB to a third party for market participation, however this would still require a regulatory waiver from the Australian Energy Regulator (AER). The findings suggest that third party owned CB can generate substantial revenue from wholesale and FCAS markets when a significant portion of the CB's capacity is leased out [33].

Beyond market participation models, the ownership structure of CBs also warrants consideration. An ARENA study [33] investigated different ownership models for community batteries. These included third-party ownership by local government or for-profit retailers, network ownership focused on increasing hosting capacity or deferring network investments, and network ownership where the battery is leased to a retailer for energy trading on a for-profit basis. The studies conclude that a reduced local energy transport price (local use of service, LUoS) is required under all ownership models to incentivize local energy exchange [35]. Discussions are already underway to refine LUoS, which would reflect the difference in network costs when using energy locally versus transporting it over greater distances.

4.1.2.1 Community batteries in Australia

Recently, community batteries have been gaining significant attention from stakeholders across Australia. In Australia there is the Power Melbourne project, aiming at creating a network of community batteries in the city of Melbourne. Two CB of 400kWh and one CB of 320 kWh have recently been installed. One notable initiative is the a GemLife Sustainable Community Battery Project, which sets to deploy 10 BTM community batteries over 8 communities across regional Queensland, NSW and Victoria. This project, which is scheduled to end in 2030, will operate as a VPP enabling the batteries to access wholesale electricity markets and FCAS markets [36].

The Gemlife Sustainable community battery project is part of a more general funding plan of around 370 community battery across Australia by ARENA (Community Batteries Funding Round 1) [37].

The CB projects funded by ARENA include both FOM and BTM batteries. FOM batteries are typically owned by network operators while BTM batteries are owned by retailers. The CB power capacity ranges from 50kW to 5 MW, for a total of 136 MW of power capacity and 281 MWh of energy capacity installed. Most of these projects feature hybrid architecture to enable value stacking, though their primary objective is to enhance solar hosting capacity.

In terms of investment costs, in general FOM batteries were more expensive than BTM batteries ($ 2.30/Wh vs $1.33/Wh, average cost). This is because, as highlighted in [37], FOM batteries tend to have higher construction and balance of plant costs. In addition to this, some network-operators are making significant investments in their digital infrastructure for managing their FOM batteries whereas most retailers are leveraging their existing digital systems or collaborating with established technology providers.

As expected, the CB exhibit significant economies of scale: larger CB cost a lot less on a $/kWh basis, as illustrated in Figure 7 as, project expenses (land acquisition, planning and balance of plant) are being spread over a larger quantity of the final product (kWh of storage).

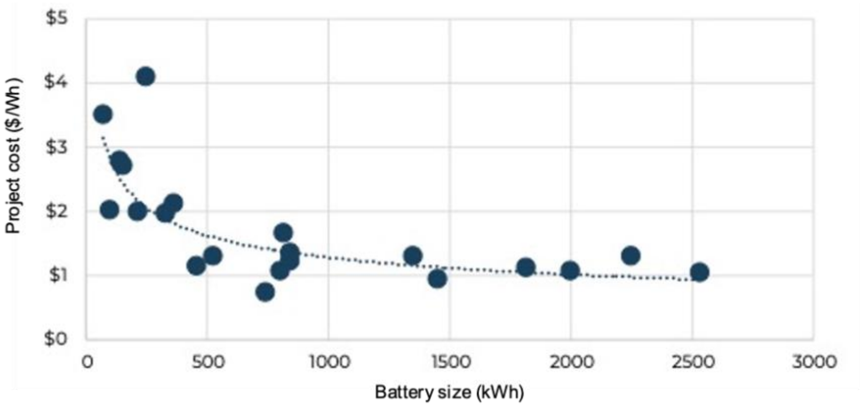

Figure 7 Total project cost ($/Wh) by average battery size (kWh) [37]

The project also enabled estimation of CB storage costs compared to other forms of battery storage. The report [37] points out that the significant cost spread in CB is indicative of an emerging market for community storge. Nevertheless, as can be seen on Figure 8, many CB are expected to be competitive with utility-scale and residential storage systems (Tesla Powerwall 2). According to the report, cost-competitiveness will be most favourable when the CB are installed as hybrid architectures and at scales above 500kWh.

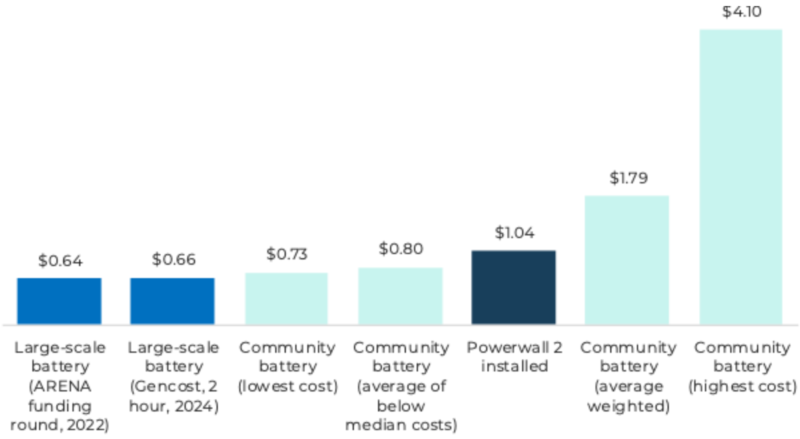

Figure 8 Total project cost ($/Wh) forecasted for different types of batteries [37]

In addition to cost considerations, another key aspect is the role of network operator-owned batteries (that are naturally FOM), which aim at providing network support. These batteries are often located in sites where they can address specific network constraints. By targeting locations requiring network augmentation, these batteries can help defer the necessary investments for such enhancements. FOM batteries could also provide voltage management or peak demand mitigation.

Similarly, 40% of retailer-owned batteries (BTM ones) plan to offer network support as well, typically focusing on sites with network congestion to potentially secure network support agreements. Furthermore, 80% BTM batteries will provide peak demand reduction services. According to the report this revenue stream is typically easier to secure, technically more straightforward to implement and more profitable than network support services [37]. In fact, some projects forecast that over 20% of their revenue will come from demand reduction alone.

Finally, resilience services were mentioned as critical by many stakeholders [33]. Four projects (FOM and BTM alike) seek to test the use of CB for resilience services. However, these services might come at the expense of others: selecting sites for resilience services may mean prioritizing back-up power provision over cost reduction or other services. Despite this trade-off, these projects will help gauge network and communities' willingness to pay for resilience services.

4.1.3 Electric vehicles

The primary distinction between storage provided by EVs and that of household or community energy storage systems lies in the variable availability of EVs [38].

Accurately modelling this characteristic requires consideration of two critical factors: type of EV charger and the proportion of EV connected to the gird at any given time.

The first key factor, the type of EV chargers, determines the EV's ability to discharge energy back to the grid, enabling vehicle-to-grid (V2G) operation [39]. In this report, chargers are categorized based on their operational modes [40] and power output [41], which are the most important features to understand the storage capabilities of this technology.

Charging operational modes define whether the connected EVs function as a simple load, a flexible demand resource, or a distributed energy storage device. The unidirectional convenience chargers, the simplest type, begin charging as soon as an EV is plugged in and lack advance control features. Unidirectional smart chargers offer more sophisticated functionality, such as scheduling charging sessions during off-peak hours. Bidirectional chargers represent the most advanced option, capable of both charging and discharging energy, thus enabling V2G integration and access to the EV's storage capacity. Enhanced charger functionalities come with higher costs. For instance, installing a 7.4 kW convenience charger costs approximately $2,500, while a smart charger of the same capacity is around $3,500, and a bidirectional charger costs about $5,000 in 2023 [42]. The higher costs of bidirectional chargers may limit their widespread adoption. Experts in Europe estimate that the penetration of V2G charging infrastructure could reach approximately 30% of the overall charging infrastructure [43].

Charging power categorizes chargers by their output, commonly referred to as types or levels 1, 2, and 3. *Type 1* chargers offer the slowest charging rates, with a maximum current of 15 A, making them suitable for overnight home charging. *Type 2* chargers provide greater versatility, operating in either single-phase or three-phase mode and supporting currents up to 80 A. These are commonly used in residential, workplace, and public settings. The fastest option, *Type 3* chargers, utilize three-phase power for rapid charging, capable of fully recharging a vehicle in approximately one hour. These high-speed chargers are strategically placed along highways, in rest areas, and at urban refuelling points, serving as the EV equivalent of traditional gas stations [41]. Figure 9 shows the accessible storage envelope (green) for 2 different vehicles with different charger size [44]. Specifically, (a) shows a 40 kWh vehicle with a 7.4 kVA charger, while (b) shows a 25 kWh vehicle with a 3.7 kVA charger. The figure illustrates that EVs with higher-capacity chargers access greater storage. This is evident at 2 am, when the vehicle with the smaller charger must begin charging to reach 100% by the 8 am disconnection time. In contrast, the vehicle with the larger charger, despite its larger battery, does not need to begin charging until approximately 4 am to achieve a full charge by 8 am.

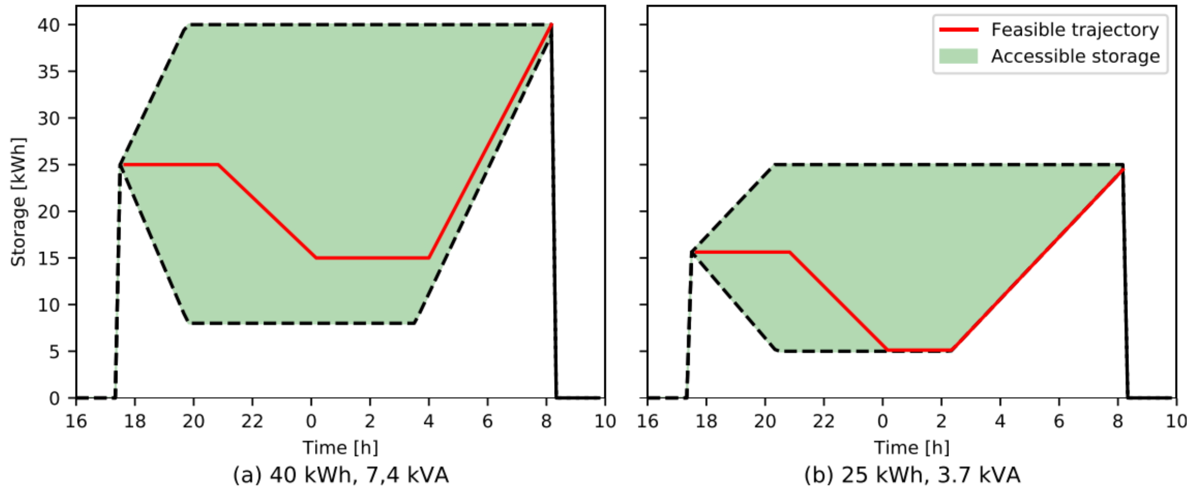

Figure 9 Accessible storage of an EV with a feasible charging (and discharging) trajectory: (a) EV with 40 kWh battery and 7.4 kVA charger, and (b) EV with 25 kWh battery and 3.7 kVA charger [44]

After understanding the charger and its operational mode, the second key factor influencing available EV storage is the proportion of EVs connected to the grid at any given time. This availability depends primarily on EV owner behaviour, influencing the frequency and duration of charging sessions, which are affected by battery size (small, medium, or large) and daily mileage [45].

The Electric Nation trial, conducted in the UK, demonstrated that as battery size increases, the number of daily charging sessions decreases [46]. Thus, EVs with larger batteries require fewer charging sessions per week, as their greater capacity enables longer driving periods before needing a recharge. Figure 10 illustrates the distribution of daily charging sessions for various battery sizes, showing that the average number of charging sessions declines as battery size grows.

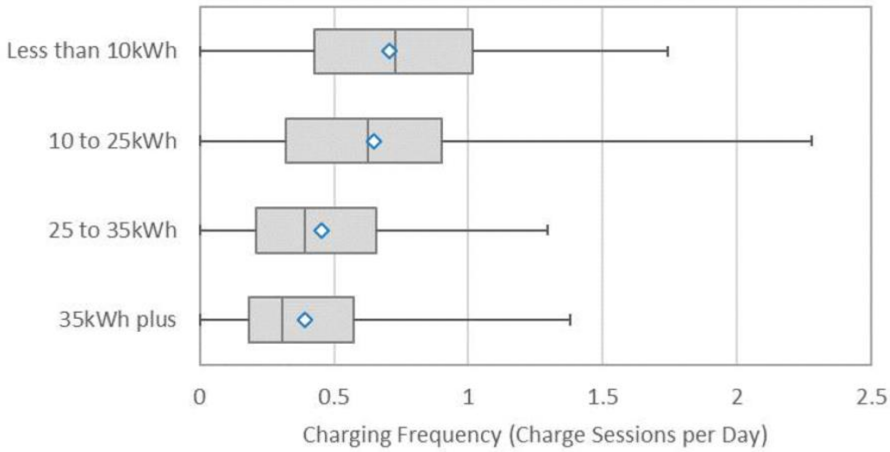

Figure 10 Distribution of median charging frequency by battery capacity [46]

Daily mileage is influenced by the owner's location and daily driving needs, leading to distinct charging behaviours between rural and urban EV owners. Rural owners, who typically drive longer distances, experience lower end-of-day states of charge and thus require more frequent weekly charging sessions. Figure 11 illustrates these differences by showing the number of weekly charging sessions for rural and urban users in the UK, considering battery sizes [44].

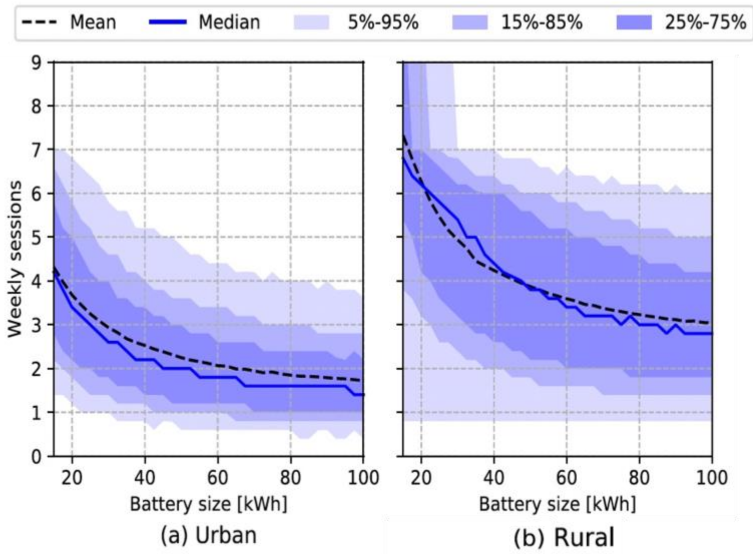

Figure 11 Charging weekly session for different battery size for (a) urban, and (b) rural consumers [44]

Furthermore, charging behaviour varies according to owner habits, categorized as systematic or non-systematic. Systematic users charge their vehicles almost daily, regardless of the state of charge, while non-systematic users charge only when the battery level is low. Figure 12 highlights how battery size impacts the connection frequency for non-systematic users, with larger batteries being connected less often due to their ability to sustain longer driving periods without recharging [44].

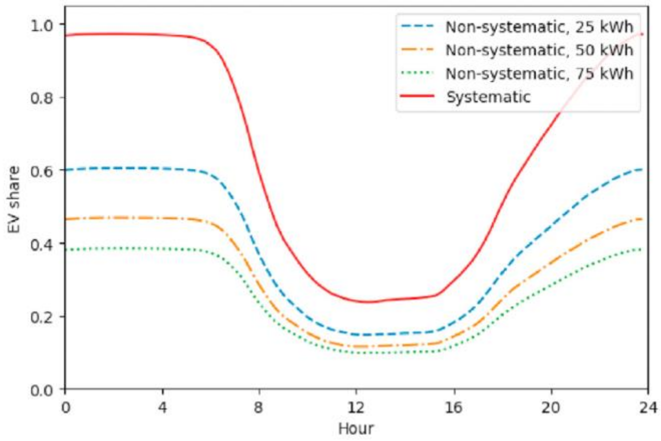

Figure 12 Average share of connected EV [44]

Accurately accounting for EV chargers and the availability of connected EVs is critical for assessing their storage value and impact on both system operation and planning.

Operationally, accessing EV storage via V2G infrastructure offers numerous benefits [47]. Research suggests that EV storage may provide frequency control services, helping to reduce the associated costs [48]. V2G may also enhance grid resilience by providing backup power during extreme weather-related outages and improve grid flexibility by balancing supply and demand, managing congestion, and improving power quality. Furthermore, V2G could offer economic benefits by reducing electricity costs, creating new market opportunities for service providers, and potentially lowering electricity prices for low-income households. Studies have shown that V2G capabilities can reduce electricity costs by an average of 28% for non-systematic users and 67% for systematic users [38]. V2G has been also highlighted as particularly valuable in office buildings, where longer connection times allow for greater cost savings [45].

In terms of planning, research indicates that incorporating EVs into models impacts transmission and generation expansion planning [49]. This impact could be even more significant if V2G-capable infrastructure is considered as an investment option, which would offer an attractive opportunity to unlock greater storage capacity within the system [50].

4.1.3.1 Electric vehicles in Australia

AEMO anticipates significant transport electrification in the future, with the number of EV and plug-in hybrid vehicles increasing across all scenarios outlined in the ISP [1]. Figure 13 illustrates the projected growth in electric vehicle adoption under various scenarios considered by AEMO.

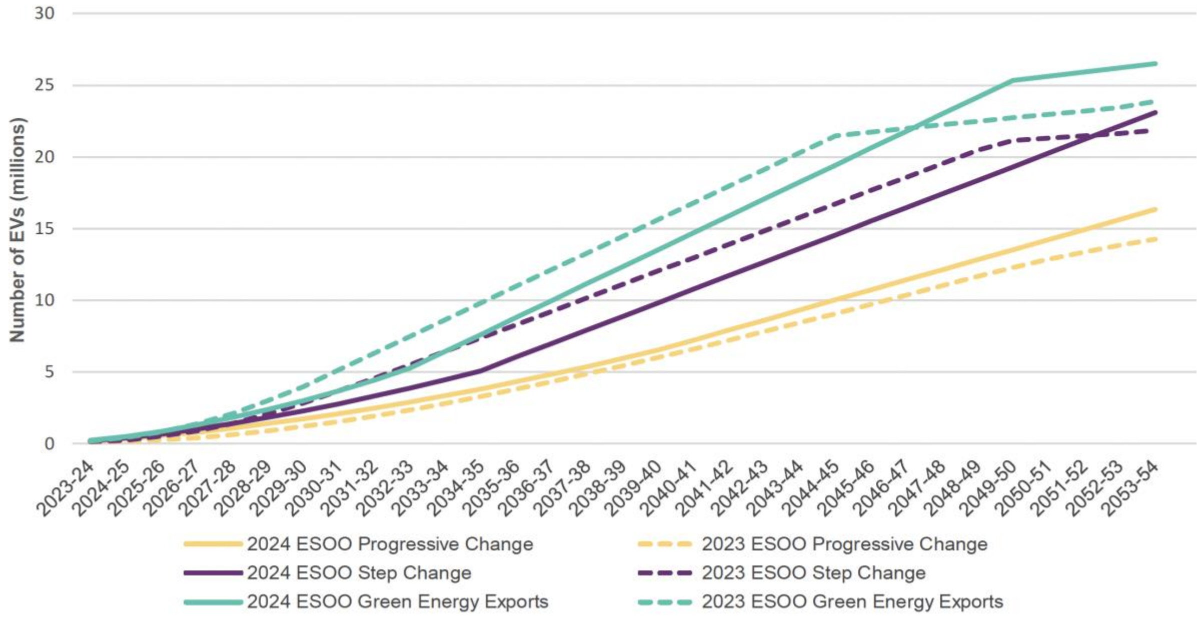

Figure 13 Number of electric vehicles projected by AEMO [1]

This large-scale adoption of electric vehicles will undoubtedly increase electricity demand. However, it also presents an opportunity to leverage additional storage and enable demand-shifting at the distribution network level. To address this, AEMO has identified six distinct user profiles based on charging behaviours and incentives:

1. Unscheduled: Charging driven by user lifestyle choices rather than cost reduction, typically occurring at residences with flat tariffs.
2. TOU Grid Solar: Charging incentivized by time-of-use (TOU) tariffs, promoting the utilization of low-cost solar energy from the grid, even for customers without their own solar installations.
3. Off-Peak and Solar: Traditional TOU tariffs without daytime incentives (except for home solar use), focused on charging during off-peak hours (primarily overnight).
4. TOU Dynamic: Dynamically priced TOU tariffs reflecting solar energy availability, used for charging only, excluding vehicle-to-home (V2H) and V2G clients.

5. Public: Charging facilitated by dedicated public infrastructure using DC fast chargers (Level 3 or higher).
6. V2G/V2H: Charging integrated with V2H or V2G capabilities, dynamically controlled by the system.

Figure 14 illustrates the projected penetration of each user type in Victoria until 2053-54 according to AEMO [18]. The combined penetration of V2G and V2H users determines the overall accessible EV storage penetration. By 2050, this combined penetration is projected to reach 24%, which is comparable to European forecasts predicting 30% V2G-capable EVs in European systems [43].

Figure 15 presents average charging profiles for four user types with an EV with a large battery [1]. The profiles for V2G, V2H, and TOU dynamic users are excluded due to their non-static demand patterns. It is important to highlight that AEMO incorporates V2G users as coordinated CER batteries within its capacity outlook and time-sequential models [1].

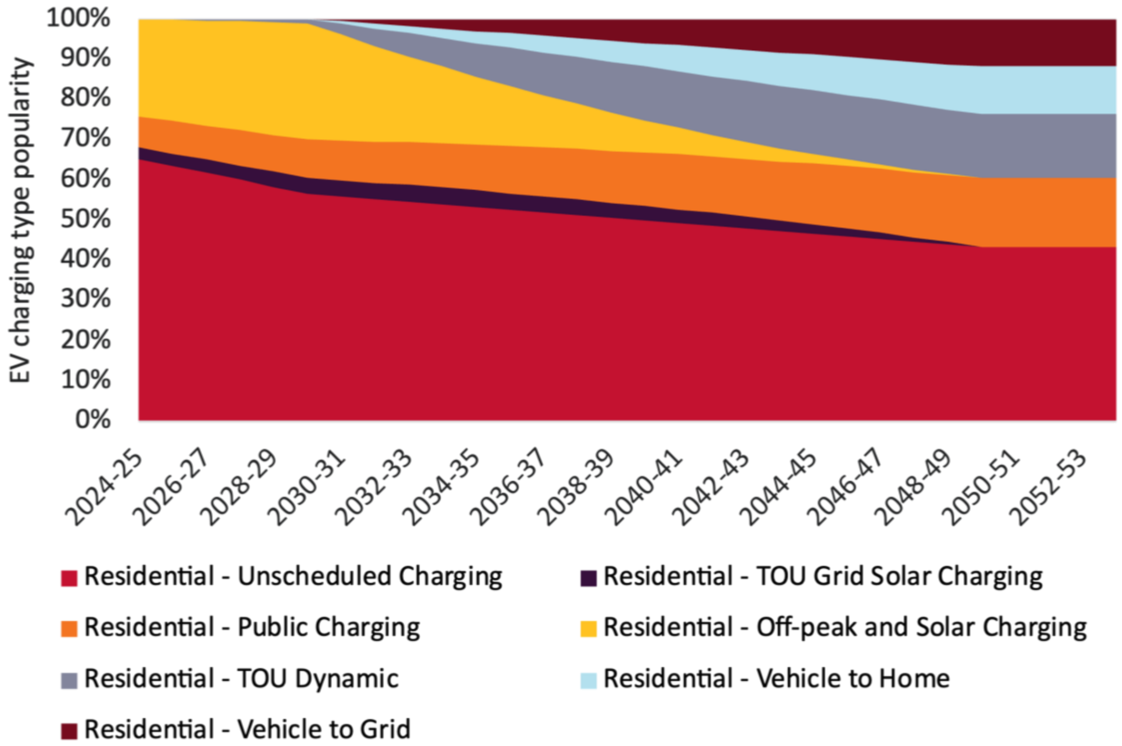

Figure 14 EV charging type popularity in Victoria based on data from [1]

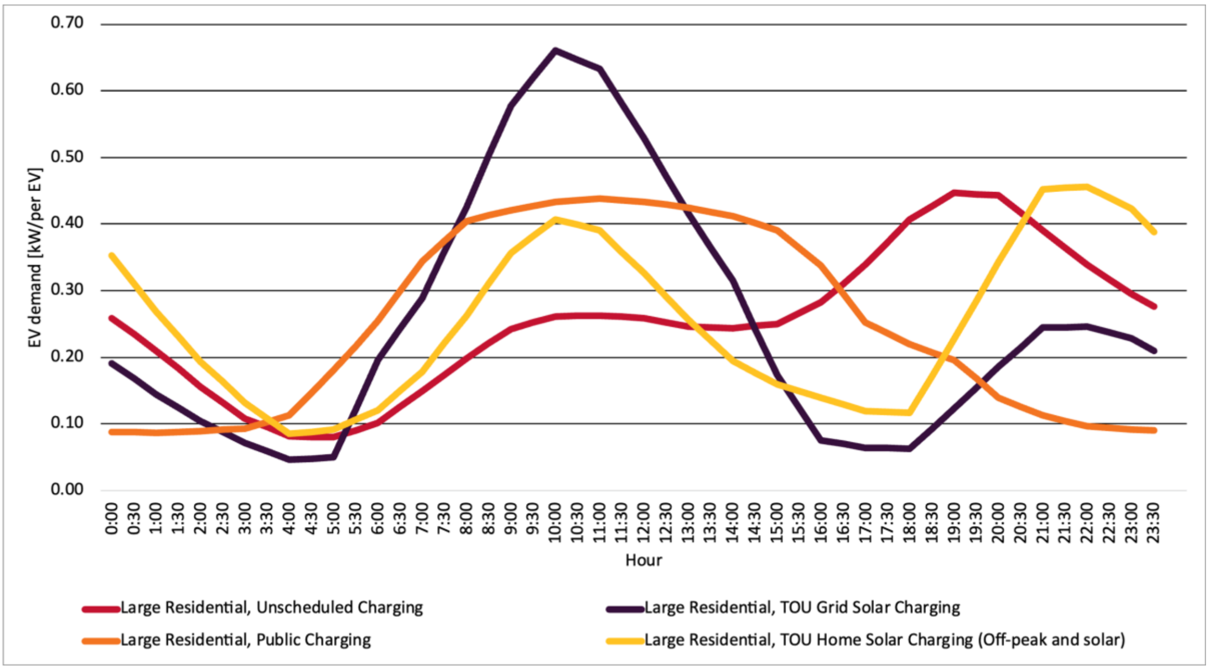

Figure 15 Charging profiles of different EV charging types for large residential vehicles in Victoria based on data from [1]

Figure 16 , created for this report based on census data from [51], shows the relationship between commuting distance to work and population density in Victoria. The figure demonstrates that in Victoria people residing in denser zones (urban areas) tend to have shorter daily commutes compared to those living in rural areas who travel longer distances.

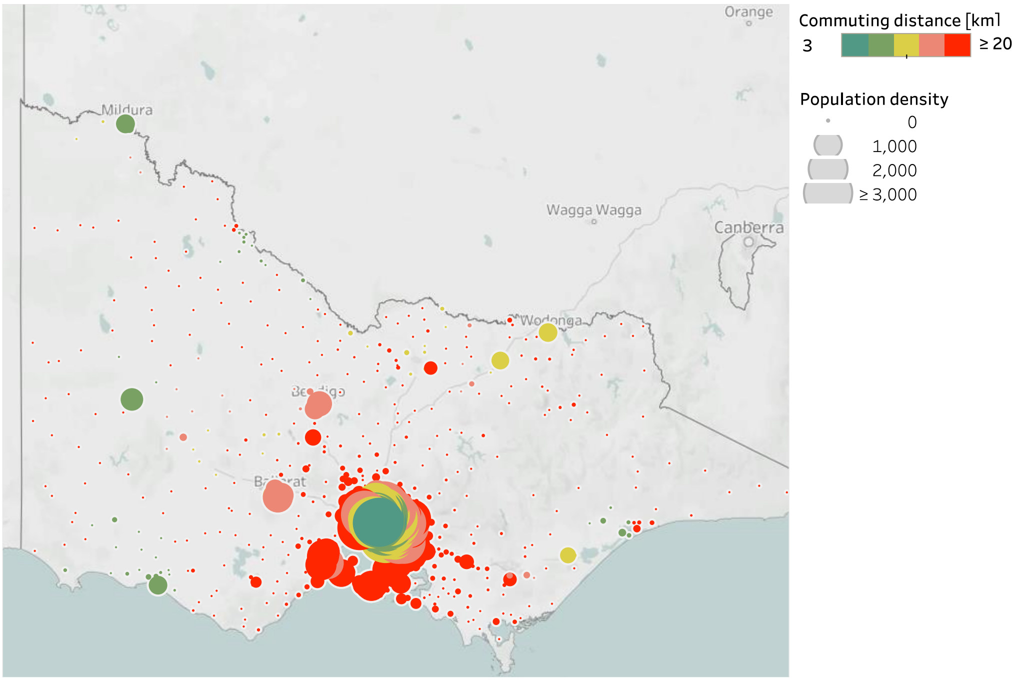

Figure 16 Commuting distance to work and density per postcode based on [51]

Figure 17 shows the penetration of electric vehicles in Victoria created with data available in [18], with large vehicles being the most prevalent, followed by medium and small cars. Figure 18 illustrates the average demand projected by AEMO for the different EV size for the unscheduled type of user, the figure is made with data available in [18]. This figure demonstrates the correlation between vehicle size and demand, with large vehicles exhibiting the highest average demand, followed by medium and small vehicles.

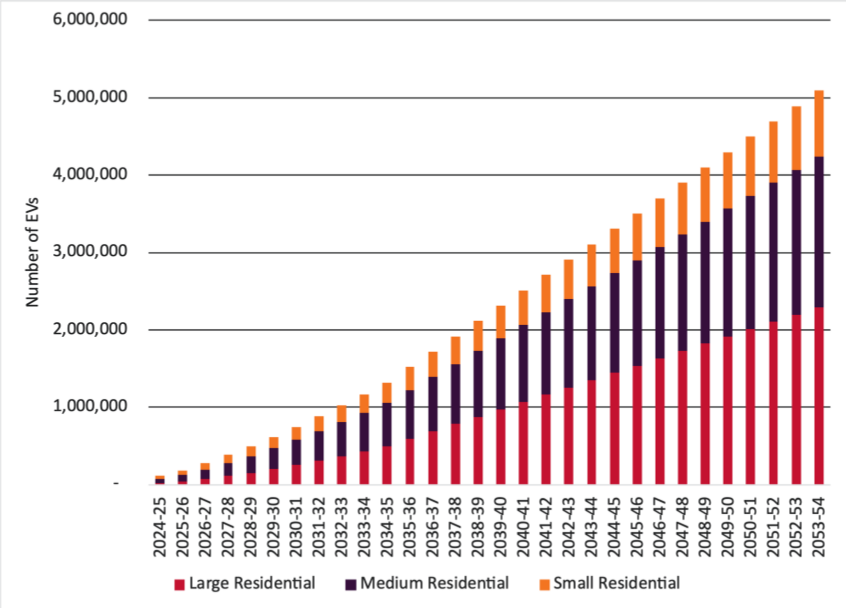

Figure 17 Number of EVs per year and type [46]

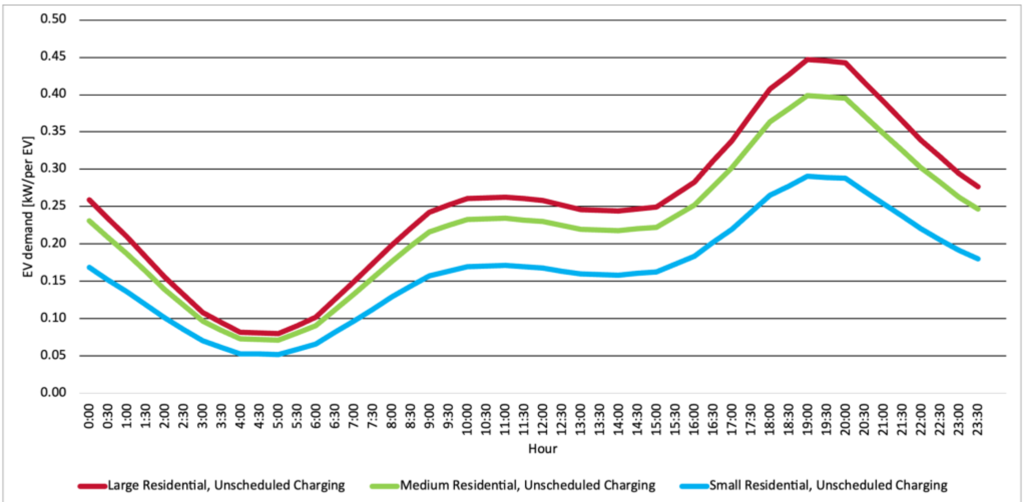

Figure 18 Average electric vehicles demand profile for unscheduled charging behaviour and vehicle size [1]

Figure 19 illustrates charger penetration in Australia. Currently, 2.3 kW chargers are the most prevalent, with 80% penetration, but this is projected to decrease to 36% in the long term. Conversely, 3.7 kW chargers are expected to increase from their current levels to approximately 44% penetration, becoming the most common type. While 7.4 kW chargers currently have low penetration, they are projected to reach 20% by 2052-53.

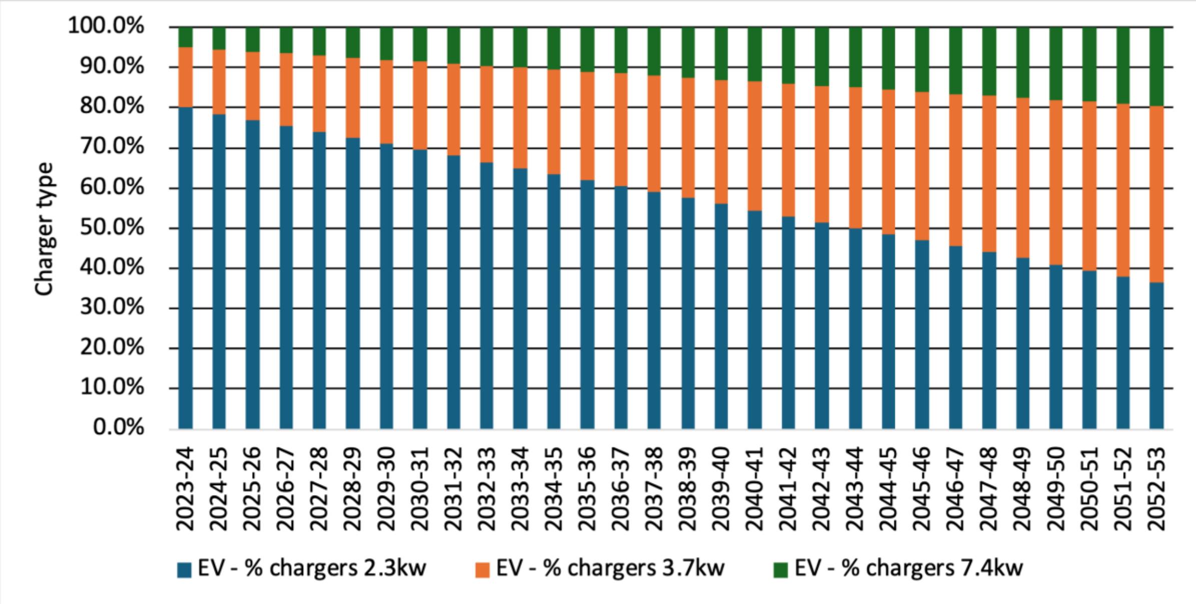

Figure 19 Charger type projections by C4NET

Although this literature review focuses on the technoeconomic aspects, the substantial changes discussed in this section regarding increased electric vehicle adoption requires new regulations and operational standards. These measures will both incentivize technology uptake and enable EV batteries to support grid services [52].

4.2 Thermal energy storage

Figure 20 illustrates average household energy consumption in Australia [53]. Combined, hot water and heating/cooling demand account for 63% of total residential energy usage. This highlights the substantial storage potential of thermal energy storage (TES) technologies. Indeed, domestic heating demand has been identified as a major source of flexibility for the energy system in Europe by 2030 [43].

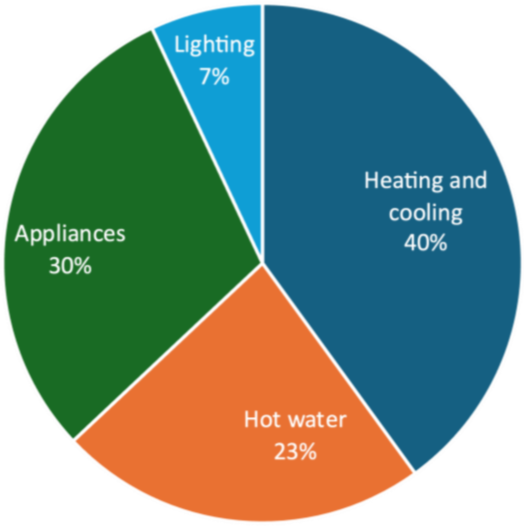

Figure 20 Average household energy usage in Australia [53]

To effectively integrate TES into the distribution system, it is crucial to understand the mechanisms for storing thermal energy at this level. TES is typically achieved through sensible heat storage, which involves storing energy by changing the temperature of a storage medium, such as solid or liquid materials.

At the distribution level, TES can be implemented in three primary ways. The first and most important approach is to treat any thermal demand as a flexible resource for demand response [54, 55]. In this way, access to the storage is enabled by the ability to reduce demand, helping to address potential power balance issues without compromising on occupant's comfort. Second, as *building fabric-related thermal storage in buildings,* which involves preheating or precooling the building structure itself, effectively "charging" the TES. The stored energy is then released ("discharged") over time while keeping the temperature in a comfort zone. Third, *domestic hot water storage*, which functions similarly by preheating water in hot water tanks for later use.

These methods allow customers to maintain thermal comfort while potentially reducing energy costs [4, 56].

4.2.1 Building fabric related thermal storage

Heating, ventilation, air conditioning, and cooling (HVAC) systems are among the most energy consuming components of buildings [53], operating as controlled loads that activate when indoor temperatures deviate from set thresholds. Buildings possess inherent thermal inertia, which can be leveraged to provide demand response (DR) services in power systems [55]. This thermal inertia acts as a buffer, enabling temporary adjustments to HVAC setpoints that reduce electricity consumption without compromising occupant comfort. By leveraging this capability, HVAC systems effectively transform buildings into thermal storage devices, temporarily reducing energy usage during DR events and then recharging by restoring energy levels after the event concludes. This approach supports grid flexibility while maintaining thermal comfort and can be implemented through either full or partial coordinated shutdown (or activation) of aggregated HVAC devices, depending on the support required by the grid [57].

Another thermal storage available in building levels is the building fabric related thermal storage (also sometimes indicated as “passive”), which is the ability of a building to store thermal energy within its airspace and structural envelope for short periods [58, 59]. This allows buildings to pre-cool or pre-heat, reducing the need for cooling or heating and, consequently, shifting energy consumption. Thus, the building functions like a thermal battery, requiring "recharging" when temperatures approach the limits of the comfort band.

This thermal storage can be utilized in two ways: for cooling and heating purposes. In hot days, typically in summer, the building is pre-cooled to the minimum comfort temperature, storing "cooling capacity." As the temperature rises, the stored energy is gradually released, reducing the need for active cooling. Figure 21 [58] illustrates this process, showing the demand of HAV components alongside the room temperature. In the figure, the electrical demand is initially increased to overcool the room and as the temperature rises within the comfort range, HVAC devices remain off until the maximum comfort temperature is reached, at which point HVAC activate again, increasing demand.

In cold days, typically in winter, the strategy is reversed. The building is pre-heated to the maximum comfort temperature, storing thermal energy. As the temperature drops, the stored heat is released until it reaches the minimum comfort limit, reducing the need for active heating during this period.

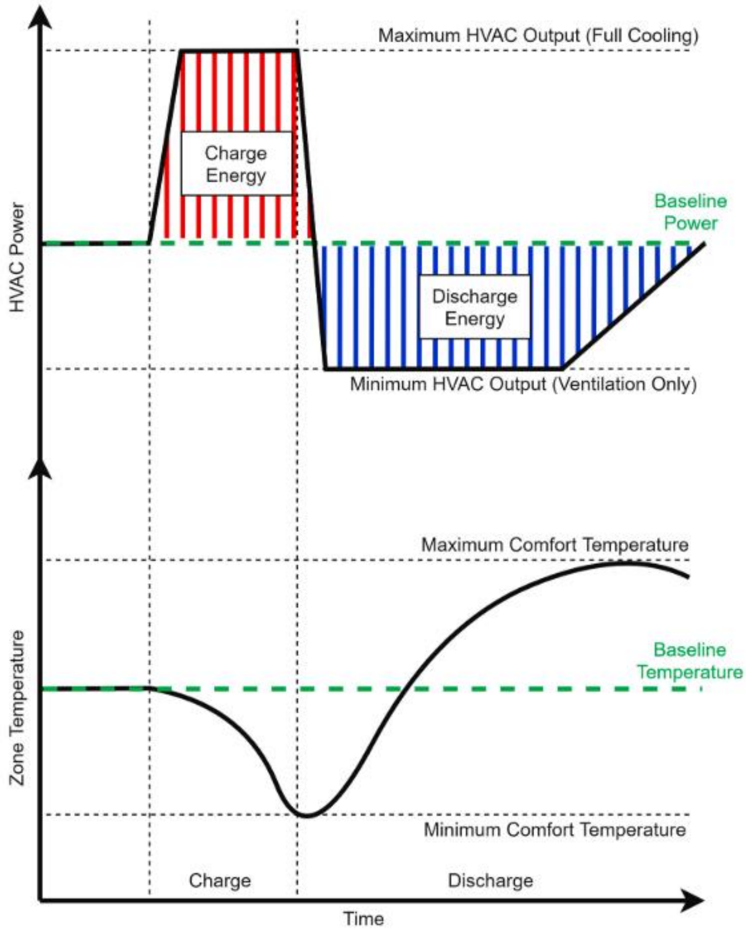

Figure 21 Charge-discharge cycle of building fabric-related thermal storage within a building [58]

Heating and cooling demand is determined by a building's energy efficiency, which is influenced by external factors like weather conditions, and internal factors, such as building size, occupancy, occupant behaviour, desired indoor temperatures, and, most importantly, building insulation [59]. Consequently, the period during which thermal energy can be effectively delivered varies between poorly and well-insulated buildings. Poorly insulated buildings can store heat for short periods, requiring up to 6 hours of preheating to maintain comfortable conditions and discharge their thermal storage within 2 to 5 hours. In contrast, well-insulated buildings require minimal preheating and can maintain comfortable temperatures for around 24 hours without heating[1] [60]. Therefore, given an electric heating or cooling demand, these technologies can be modelled using a load-shifting approach based on the duration a building can maintain a comfortable temperature.

4.2.1.1 Building fabric-related thermal storage in Australia

In Australia, residential buildings can be classified by type (detached house, semi-detached house, apartment), household size (1 to 4 occupants), and energy efficiency based on construction year (Old: before 1991; Modern: 1992–2006; New: 2007–2011; Efficient: after 2012) [61]. Notably, more energy-efficient buildings require lower-capacity heating and cooling appliances to maintain comfortable indoor conditions, resulting in reduced energy consumption and improved thermal storage capacity.

While official projections for the demand response (DR) capabilities of fully electrified Victorian buildings are unavailable, this literature review makes several assumptions to explore this potential. Based on the current distribution of dwelling types across Australia (Figure 22, derived from 2021 census data [62]) and using the tool from [61], a heating demand profile for Victorian dwellings in 2021 was developed (Figure 23), assuming 100% electrification of heating via heat pumps. This profile indicates a potential peak demand in Victoria of approximately 5 GW, which could unlock substantial DR capacity, maximizing building storage potential. Academic research in Melbourne has shown that strategically applying building thermal storage for peak demand management during extreme heat events through DR could yield cost savings of $3 million [63].

[1] Prolonged preheating should be avoided in well-insulated buildings due to their susceptibility to overheating.

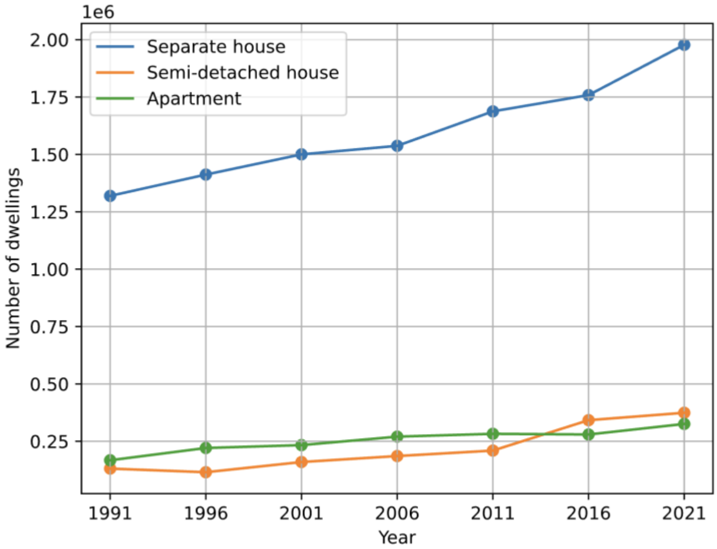

Figure 22 Type of dwellings in Victoria per year

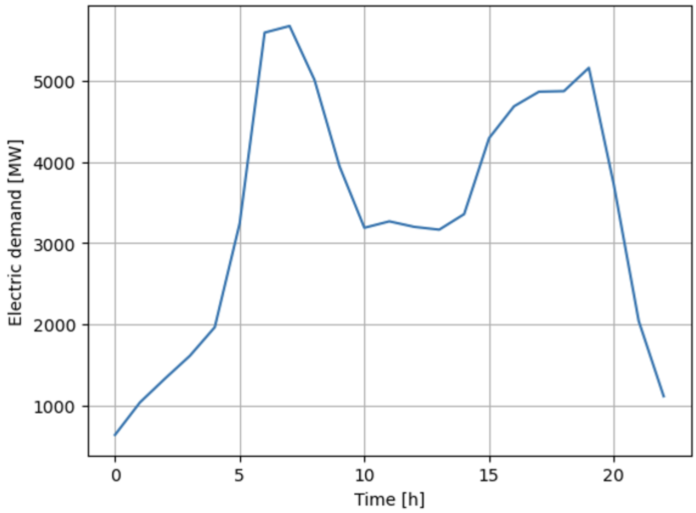

Figure 23. Aggregated space conditioning demand for Victoria on an average winter day considering 100% electrification of the demand for 2021

Similarly to the DR case, there are no official projections for building fabric-related thermal storage in the Australian market. However, academic research has provided valuable initial insights. Particularly, the economic benefits of building fabric-related thermal storage in the Australian building sector have been the subject of several studies. A theoretical examination of the integration of building thermal storage into the Australian market was undertaken in [58]. This initial work was subsequently complemented by numerical simulations, documented in [64], employing a 5-minute market model based on a South Australian case study. This study indicated that pre-cooling strategies could yield energy cost reductions of up to 14%. Further research, also focusing on South Australia, demonstrated that pre-cooling commercial buildings for 2 to 12 hours during periods of extreme heat could achieve peak demand reductions between 3.4% and 6.6% [65].

4.2.2 Domestic Hot Water (DHW)

DHW systems are either storage based (water is stored in a tank and kept hot, ready to be used at all time) or instantaneous (water is only heated as required 'on-demand' and hence not stored). There exist different DHW technologies, the main ones being gas hot water heaters (storage or instantaneous), heat pumps (storage), solar (storage with an electric or gas heater booster) and electric hot water heater (storage or instantaneous) [66]. Off-peak electrical storage based DHW systems are already used to shape demand, charging during the night to create demand when thermal generator must continue to operate and reducing peak demand during the day.

The DR principles outlined in Section 4.2.1, which treat buildings as thermal storage devices, can also be applied to domestic hot water (DHW) systems. Similar to buildings, DHW tanks store thermal energy and can be strategically managed to provide DR without impacting user comfort. In particular, some modern DHW tanks offer enhanced DR capabilities through *stepped control*, which allows these devices to modulate their power consumption in fixed increments rather than simply switching on or off [67]. Therefore, with proper coordination, DHW systems can unlock significant DR potential.

An alternative strategy for exploiting the storage potential of hot water tanks involves shifting heating operations from off-peak periods to periods of peak renewable energy generation. The feasibility of this approach depends on the thermal storage capacity of the tanks, typically ranging from 6 to 8 hours during off-peak periods and 4 to 6 hours during solar soaking operations [68]. For instance, instead of heating from 10 pm to 6 am, a hot water tank could be heated from 12 am to 5 am and then from 11 am to 3 pm to coincide with peak rooftop PV generation. This strategy is supported by the findings of Parra et al. [39] who demonstrated that combining a DHW storage system with a PV controller (solar soaking) is the most cost-effective method for storing excess PV generation in UK homes already equipped with water tanks.

Solar-soaking from DHW also has some benefits on network voltages: shifting the demand to daytime can help alleviate the voltage rise stemming from solar exports [68]. Another interesting insight from [68] is the high predictability of the DHW demand and its strong correlation with outdoor temperature (DHW demand increases with cold temperature and vice versa) which assist DNSPs in their network and market operations.

4.2.2.1 Domestic hot water in Australia

Water heating accounts for around a quarter of Australian household's energy use [69]. At present, there are about 10.2 million DHW devices in Australia (roughly one per household), with 830,000 DHW devices being sold annually (79% of those are used as replacement of previous DHW devices, and the rest being installed for new homes) [69]. A detailed technology repartition in Australia is illustrated on Figure 24, with the most common being electric, then gas and then heat pumps. Electric resistance storage is the most prevalent technology in Australia (4.5 million), followed by instantaneous gas (2.4 million), storage gas (1.4 million), solar (1.2 million) and heat pumps (350 000) [69].

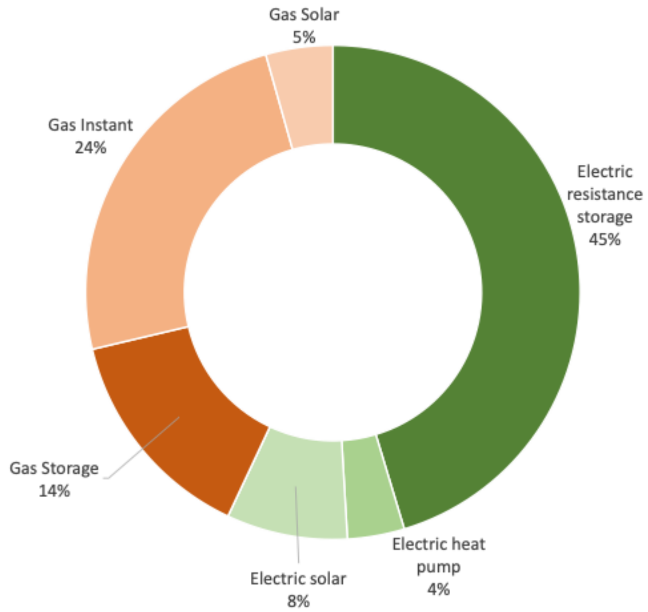

Figure 24 Shares of different DHW technologies currently deployed in Australia [69]

Electric storage water heaters generate heat by passing electricity through a resistive element and storing it in a tank. They are relatively affordable to install, with prices ranging from $600-$2600 in 2023 [69], and typically have power ratings between 2.5 and 5.0kW. However, the rise in electricity tariffs make them most expensive to operate, unless paired with rooftop PV or off-peak tariffs. Recent updates to the National Construction Code (NCC) have effectively banned electric storage DHW systems due to their high carbon emissions compared to electrical heat pump [69]. Despite this electric storage remains the most common DHW system, as it is used by around 50% of households, accounting for around 25 GWh/day (around 5%) of daily electrical consumption across the NEM [69].

On the other hand, instantaneous gas water heater, have become increasingly popular option in Australia and are relatively cheap to install with an initial cost between $750 and $1800 in 2023 [70], whereas storage gas systems are generally less efficient and cost competitive than other units and hence less popular.

Solar electric water heater often incorporates an electric resistance or gas burner to boost water temperature, if needed. This technology has the highest initial cost, ranging from $3600 to $7000 in 2023 [71], but is one of the cheapest to operate. Despite its cost-effectiveness in operations, sales have been declining in recent years with less than 40,000 units sold in 2021 [71]. This declined can be attributed to several factors including the increasing popularity of rooftop PV, which occupy valuable rooftop space, the availability of more affordable alternatives (such as gas) and the growing popularity of heat pumps.

Heat pumps (HP) water heaters employ electricity to transfer heat from one place to another rather than producing it directly. The systems have a coefficient of performance (COP) – the ratio of heat energy delivered to amount of electric energy consumed – ranging from 3 to 5, which is significantly higher than other technologies and lead to substantial reduction in electricity use. However, one notable restriction for the adoption of HP water heaters is the availability of suitable installation space [69]. This constraint is particularly common for buildings in high-density urban areas (apartments) where outdoor space is limited or non-existent. It is important to note that many models also include a resistive element to enhance output during colder months. HP are among the most expensive technologies to install, with pricing ranging from $3000 to $5000 in 2023 [71]. Their typical power rating is below 1 kW for standard models and between 2 and 5 kW for models with a resistive booster [69]. This device may need some additional regulation because, as of now, there is no minimum energy performance standard (MEPS) for HP water heaters [69], which might be a challenge for the adoption of this technology.

In Australia there is an increasing interest in using existing DHW storage systems for solar soaking [72]. Several ongoing projects are exploring this potential: in New South Wales, over 6,000 DHW systems are being trialled across three projects (averaging 2,400 DHW systems per project) [69]; in Western Australia, 250 DHW systems have been trialled; in Victoria, projects are underway to recruit at least 10,000 DHW systems [72]; and in South Australia, 21,500 DHW units are being tested to provide services [68], including the Rheem trial (completed in 2024), which investigated the benefits of DHW controllability and concluded that it could reduce peak demand [67].

Figure 25 summarises the previous list, showing the growth of approximate number of clients and the associated estimated total annual energy consumption from electric storage DHW systems participating in the different trials in Australia. This plot was generated using the approximate number of customers in each project and the model developed in [61]. For the sake of clarity and simplification, all ongoing projects have been projected to reach completion by 2025. We assume a uniform increase in the number of participants per year for each trial, and we assume that all customers are using electric storage DHW.

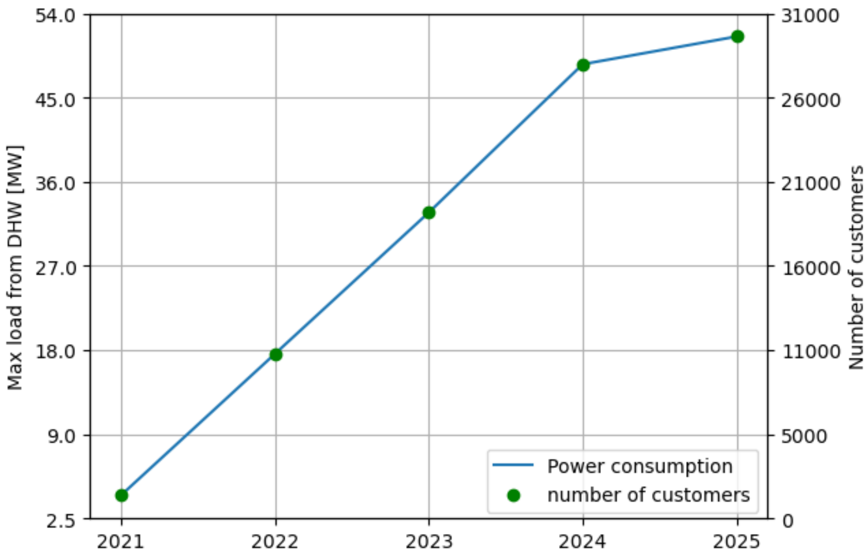

Figure 25 Estimate of the annual energy consumption of the different customers participating in DHW trials in Victoria.

The potential impact of DHW storage has been studied with real-world projects, with the PLUS ES project (2022-2024) standing out as the most insightful due to its scale. As the project with the largest number of controllable DHW units it demonstrated an estimated 11.6 GWh of shifted DHW demand. On average each household experienced an annual shift of 0.9 MWh in their DHW demand, which is equivalent to a daily shift of 2.5 kWh from DHW. Assuming retailers have total exposure to wholesale market prices, the report from the Plus ES project [68] estimates that monthly financial benefits for the retailer varied between $18,000 AUD and $110,000 AUD, for a total wholesale gain over the course of the trial estimated at more than $790,000. Interestingly losses for retailers only happened in June 2024, as prices spikes coincided with load shifting operations resulting in $22,000 of losses for that month.

Although numerous projects exist, there are no official projections for the growth rate of this technology. It is important to make an attempt to estimate its potential impact across the whole state of Victoria. In this literature review the projected electric demand profile for DHW in Victoria is presented in Figure 26, based on 2021 census data [62] and the tool provided in [61]. This profile was developed considering the existing buildings in Victoria, with a scenario where DHW demand is fully electrified and resistive DHW systems provide hot water on an average winter day. Figure 26 indicates that peak demand for DHW in Victoria on such a day could reach around 3.5 GW. On such a day, the total energy provided by the DHW fleet in Victoria is 17.8 GWh, which translates into a daily demand of 7 kWh per DHW device.

This number aligns with [68] where it is estimated that a controllable DHW has an average demand of 6 kWh per day. This report suggests that by strategically coordinated and shifting DHW to align with solar generation period, a significant portion of this curtailed energy could be effectively harnessed for water heating purposes, hereby reducing curtailment. Even more so that, the potential of DHW shiftable demand can reach up to 22.7 GWh by 2040.

Passing on the benefits to participating households could result in an annual benefit of $63 per household, which is likely to increase as electrical demand increases due to electrification [68]. This incentive may encourage more customers to allow their electric DHW systems to be controlled, potentially alleviating the issue of 25% of the controllable fleet being inactive.

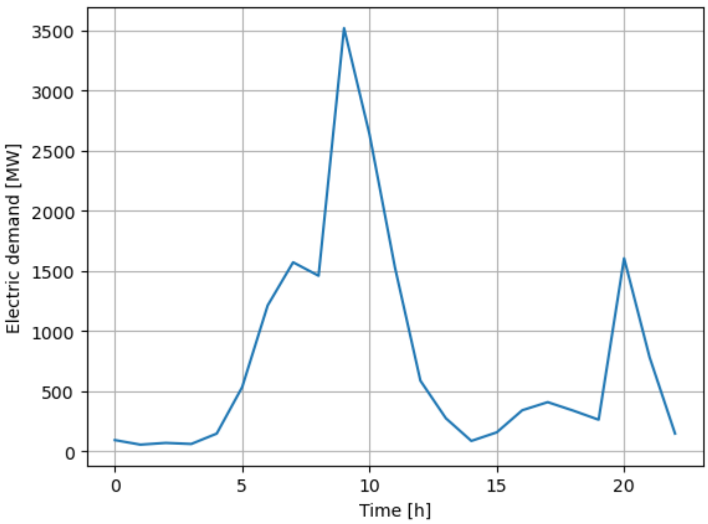

Figure 26 Aggregated DHW demand for Victoria on an average winter day

5 Concluding remarks and next steps

This report offers a comprehensive overview of emerging storage options connected to distribution networks and their current and expected development in Australia, encompassing household and community batteries, electric vehicles (EVs), and thermal storage, such as building fabric related thermal storage and hot water tanks. It clarifies the potential of these technologies by outlining the key elements for modelling, benefits, and roles in future power systems, offering valuable insights for both customers and grid operators. Thus, the literature review conducted in this report yields several key findings regarding the deployment and utilization of these storage technologies.

Household and community batteries can contribute to upstream grid services, making their consideration crucial for future operation, where it is expected a widespread adoption. To fully harness the potential of household batteries, their aggregation through virtual power plants (VPPs) will be essential, enabling them to provide valuable upstream services. On the other hand, community batteries, with their larger capacity and greater potential for delivering higher benefits, may present a more attractive investment opportunity for communities. Therefore, developing a thorough understanding of the role these batteries play and their interactions with other storage technologies is key to unlocking their full potential.

The storage capacity of electric vehicles (EVs) is inherently variable. Realizing their potential as distributed storage resources depends on widespread adoption of bidirectional chargers and effective Vehicle-to-Grid (V2G) integration strategies. EV storage availability will be significantly influenced by owner behaviour, which is impacted by vehicle size, commuting distance, and potentially tariff incentives.

Thermal storage offers valuable demand response capabilities during contingencies, significantly impacting system operation by unlocking currently inaccessible resources for system operators. Furthermore, these technologies can reduce peak demand through demand shifting (pre-colling and/or pre-heating), typically for a few hours for building fabric storage; and by shifting hot water demand profiles consumption from peak evening hours to solar hours, and from peak morning hours to night hours.

Ultimately, this report provides a base for integrating emerging storage options into mathematical models, which will be crucial to understand the individual capabilities and potential synergies. Thus, next step of this project involves developing accurate models for these technologies, which will provide valuable insights into the challenges and opportunities associated with distributed storage deployment, enabling more informed decision-making and strategic planning.

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