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Financial Viability of Community Scale Battery Ownership Models

prepared for:
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Executive Summary

The use of behind-the-meter batteries can provide individual consumers with considerable financial benefit in the form of lower electricity bills, and the potential to put downward pressure on electricity prices for all consumers by reducing the need for investment in additional electricity infrastructure. However, many consumers – for example, renters, apartment dwellers and low-income households – are and will likely continue to be unable to install batteries.

Community scale batteries offer the potential for consumers who cannot install their own batteries to invest in the same technology, but with that technology located on the grid-side of the meter. Grid-side batteries are able to generate a number of financial benefits that are not available to individual end consumers with batteries. These additional benefits stem from the ability of a grid-side battery to interact with the wholesale electricity market, frequency control and ancillary services market, and by providing network support. These are unlikely to be accessed by individual end consumers.

The objective of this assignment, as described in the project brief, was to “assess the economic case for community scale (100 kWh-5MWh) batteries under current economic, regulatory and technological settings”.[1]

The key activities undertaken to address that objective included:

- Conceptualising relevant community-scale ownership business models;
- Information gathering regarding, for example, battery size and costs, historical wholesale prices and frequency control and ancillary services prices; and
- Modelling the estimated financial benefits under each of the ownership models.

The following ownership models were assessed:

- Ownership by a network related party
- Ownership by an electricity retailer
- Ownership by a community group.

We did not consider a model in which an electricity network business served as the owner of the community-scale, grid-side battery for several reasons. This decision was based on the fact that e primary reason for this decision is that was that there are no natural monopoly elements to the provision of a community-scale battery or the services that can be provided by those batteries. Hence, these assets and services, based on our understanding of the Rules, should not form part of the regulated assets or services that are offered by a DNSP. DNSPs should, and under the Rules are incentivised to, purchase services – including services provided by a battery operator – from the competitive market where that will provide a distribution service at an efficient cost.

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[1] For the avoidance of doubt, the present study has not considered the potential impacts of the various reforms and changes that are currently being considered within the NEM including CoGATI, ESB 2025, or the possibility of a two-sided market being instituted, or any other changes that could result from Rule changes that could be developed in the future.

In our view, there is no reason to believe the competitive market will not function efficiently with regard to the provision of community-scale, grid-side batteries where: it has access to (a) information about the locations in which community-scale batteries could be of most value and (b) price signals that reflect the value of the services that the battery can provide to various parts of the electricity value chain.

In-house spreadsheet models were used to assess the magnitude of the following types of benefits that could be expected to accrue to community-scale, grid-side batteries under each of the ownership models noted above, and to behind-the-meter batteries owned by end-use customers and operated primarily for retail arbitrage purposes.

Results indicated that:

- All three of the grid-side community scale battery ownership models outperform an individually owned, behind-the-meter battery. This is because, under current regulatory settings, an individual end-use customer cannot access a number of the benefits available to a community-scale battery, including wholesale electricity market arbitrage and the FCAS market.[2]
- Of the three community-scale ownership models tests, the retailer-owned model produces the highest level of benefit to the asset owner. This is because the retailer can interact directly with the wholesale market, thereby gaining the full benefit available from the wholesale electricity price arbitrage and FCAS revenue streams.[3]

The scale of benefits available to the owner of the asset is important as, everything else being equal, the party that has the largest potential returns will be in the best position to out-compete other parties to invest in any particular opportunity to deploy a grid-side battery. It is also the case that a greater level of benefit provides more potential for those benefits to be shared with end consumers. However, the motivation of different types of owners to do so is also likely to vary.

Of the three types of owners considered, it seems likely that a community group would be the most likely to provide the greatest share of the benefits to end users. This sharing of benefits could take many forms ranging from (a) 'dividend' payments to those community members that have invested in the battery (i.e., that have provided funding for the purchase and/or operation of the battery), to (b) payments/rebates customers whose PV export was provided to the community battery, or (c) investments in assets or services to the community as a whole (e.g., use of the net revenue to fund community events, assets such as a park or play equipment, or services such as sponsored child care).

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[2] Such access could be provided by a VPP, but the costs of operating a VPP is almost certainly higher than that of a community-scale battery, thereby reducing the expected level of total benefit.

[3] In the other two ownership models the network-related party or the community group could enter into a tolling arrangement with a retailer to gain access to the revenue streams available from the wholesale electricity market and FCAS (or a non-retailer party that is a registered participant in the case of FCAS). However, this would require a split of the revenue from those sources of benefit. Although a network-related party or a community group could become a market participant and gain direct access to those benefit stream, this is considered unlikely given the cost and additional level of responsibility this would entail.

A retailer owner of a community battery might use some of the net revenue to make payments to its customers within the area whose PV export was provided to the community battery, or to provide an incentive to end-users within the area to become a customer of the retailer. However, as a commercial entity, a retailer would be likely to want to retain a larger percentage of the net revenue achieved than a community group.

A network-related party would similarly be expected to provide a return to its shareholders, and unless it was also providing some form of direct service to end customers, however, it would not appear to have the same motivation as a retailer to use a share of the net revenue benefit to seek to 'win' or influence end customers.

Benefits to end consumers from the grid-side community scale battery ***regardless of the ownership of the battery itself*** include the following:

- For all end consumers in the distribution network, the potential to benefit from lower network tariffs due to the deferral of local network augmentation costs, assuming that the battery is located in areas that may otherwise face some form of constrain (which in theory should be signalled to the market via a cost-reflective price signal regarding the value of network deferral);
- For all end consumers within the local area served by the grid-side, community scale battery:
  - the potential to consume locally generated, carbon-free electricity (to the extent that the community battery purchases and re-injects rooftop PV electricity generated within the local area); and
  - the potential to continue to have access to electricity supply (from energy stored in the community-scale battery) during a supply interruption that occurs upstream of the local area (e.g., a generation failure or an upstream network asset failure).

Where the grid-side battery is owned by a community organisation there is also the potential to participate as shareholders in the community-scale battery and potentially earn a share of the profits of the battery operation, and/or potentially benefit through other community uses of the profits of the community-owned battery sponsored by the community group.

The benefits of grid-side, community-scale batteries would appear to be able to be maximised by:

- Ensuring that cost-reflective price signals are available for the services that these devices can provide in deferring or reducing the need for augmentation to the network. This will maximise the potential benefit of the services available from these devices, and
- Arranging means to make it easier for a community-owned battery to gain access to other revenue streams that are currently only available to market participants (i.e., wholesale energy price, FCAS and potentially any new price signals that may be put in place for system security and/or stability). This can most readily be done by allowing non-retailer parties to provide services in these markets, as has already been done whereby Small Generator Aggregators can bid into the wholesale electricity market and DR Aggregators can provide ancillary services. Any arrangement that expands the avenues through which a community battery can gain access to the wholesale and ancillary services markets will increase competition for the service that this asset can provide and therefore should be expected to increase returns to the community group owning the asset, and to these respective markets, thereby increasing the total benefit available.

1. Project background and purpose

1.1. Background

The use of batteries can provide individual consumers with considerable financial benefit in the form of lower electricity bills, and the potential to put downward pressure on electricity prices for all consumers by reducing the need for investment in additional electricity infrastructure. However, many consumers – for example, renters, apartment dwellers and low-income households – are and will likely continue to be unable to install batteries.

Community scale batteries offer the potential for consumers who cannot install their own batteries to invest in the same technology, but with that technology located on the grid-side of the meter. Grid-side batteries are able to generate a number of financial benefits stemming from their interactions with the wholesale electricity market, frequency control and ancillary services market, and by providing network support to the location transmission and distribution businesses. Grid-side batteries can also allow investors to reap the benefits of improved economies of scale, as compared to an investment in smaller batteries behind-the-meter. Grid-side batteries – depending on the energy source used for charging them -- can also provide the same non-economic benefits as behind-the-meter batteries, such as a reduction in carbon emissions and the ability to provide energy in local areas that might otherwise be affected by supply interruptions.

1.2. Objective

The objective of this project as described in the brief is to “assess the economic case for community scale (100 kWh-5MWh) batteries under current economic, regulatory and technological settings”[4]. Further consultation with the TEC project manager clarified that the project is to provide a financial assessment, in which:

- the financial attractiveness of a community-scale battery under different ownership models (as different owners may incur different costs and obtain different benefits) is assessed and compared to the financial attractiveness of household (i.e., behind-the-meter) batteries[5], with this based on current retail prices and network tariffs (as opposed to economic values), and
- how the current Rules and regulatory framework (including consumer protection arrangements) would affect (or need to be changed in the case of) each of the ownership models.

Furthermore, the RFP states that the report is to also outline:

- Basic technical requirements to maximise consumer returns from storage (e.g. capacity and charging/discharge rates; islandability; portability; microgrid potential; etc.);
- Regulatory context and challenges (including single community batteries versus aggregated household batteries in microgrids and options for innovative network tariffs);
- Potential negative impacts and risks (e.g., the limited lifespan of batteries; competition from home batteries; networks monopolising this market; etc.); and
- Relevant metering & consumer protection requirements.

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[4] For the avoidance of doubt, the present study has not considered the potential impacts of the various reforms and changes that are currently being considered within the NEM including CoGATI, ESB 2025, or the possibility of a two-sided market being instituted.

[5] Meaning individual household batteries. This did not include consideration of VPP arrangements.

1.3. Approach

The project approach was comprised of three main steps, as follow:

- An inception meeting that:
  - Provided an opportunity to review the project scope and discuss key inputs to the modelling, including the key characteristics of the three ownership models and counterfactual to be investigated and the level and structure of the retail tariffs to be used in assessing the potential benefits to consumers under each of the ownership models;
  - Identified case studies that could potentially provide useful information about the operations of one or more of the business models to be assessed; and
  - Put us in touch with modelling being undertaken by the ANU on community-scale batteries with ARENA funding to determine where the two efforts could inform and profit from one another.
- Information gathering regarding, for example, battery size and costs, historical wholesale prices and frequency control and ancillary services prices;
- Modelling the estimated financial benefits under each of the ownership models; and
- Developing this report.

2. Ownership models explored

Three community-scale ownership models were conceptualised for inclusion in the study:

- Ownership by a network related party
- Ownership by an electricity retailer
- Ownership by a community group.

Box: 1: Why we did not consider a network ownership model

We did not consider a network ownership model in this report as it would effectively provide a very significant advantage to the local network service business in being the best-positioned provider of a community battery service within its operating area. This is because the network business is in the best position to understand the value that a battery in any particular location can provide to the network itself. This understanding comes from the DNSP's ownership of and access to data on its operations, which arises from the business' position as a monopoly service provider and would put the DNSP at a competitive advantage in offering community battery services.

To our mind, it is difficult to see why this would facilitate outcomes that are in the long-term interests of consumers, particularly when (a) the majority of the services provided by a battery (and which are discussed in this report) are offered for sale into a competitive market (e.g., the wholesale market, FCAS market and/or retail market); (b) the ownership, operation and maintenance of a grid-connected battery does not exhibit any natural monopoly features; and (c) such treatment in effect means that a distribution business is conferred a monopoly right to provide battery services, as a result of the monopoly power that they have as a provider of a completely different service – i.e., *network services.*

> To do so would *in effect mean that* we are limiting competition in upstream and downstream markets, simply due to the natural monopoly characteristics of the distribution system.
>
> In saying all of the above, it is important to note that we are not suggesting network businesses should not be able to procure services from a grid-scale battery (e.g., network support services) and be provided with a regulated allowance for the recovery of those operating costs. There should be no (and in actual fact there isn't any) limit on a DNSP doing this, where it is economically efficient. This can be accomplished by the DNSP identifying a need for a service and publicising that for tendering by the competitive market. Purchasing that service from the party that can provide it at lowest cost is in the interests of all network tariff payers. This would avoid confusing the need of a network (as a regulated monopoly service provider) to procure a service with the provision of that monopoly (regulated) service itself.
>
> Finally, and for the avoidance of doubt, we are of the belief that allowing networks to own these assets (and roll them into the RAB) is unlikely to be able to co-exist with a broader market for grid-connected batteries. Given that a network business can accrue benefits that others in the market can't (e.g., if they do not send price signals to the broader market regarding the value that a service provides them – e.g., network support - then only they can reap those benefits), they in effect will end up being a monopoly provider of grid side battery services to end customers in their area, as they can extract more consumer surplus than other potential competing battery providers.

For each of the ownership types the quantitative analysis seeks to assess only the financial benefits and costs that accrue to the battery owner(s). In each case, the owner could act as a manager of benefits that are then distributed to end users. It should be recognised, however, that even if the owner were acting in this way, the maximum benefit available for distribution would be limited to the net financial benefit obtained from the owner's investment in and operation of the battery. Any required return by the owner would further limit the financial benefits available for distribution to end users.

Those benefits and costs are then compared to the costs and benefits that an individual customer would incur in purchasing and operating their own individual battery storage system.

Each of the community-scale ownership models is briefly described in the following sections of the report. It is important to note that in each case we have assumed that:

- The community-scale battery owner seeks to benefit from as many value streams as possible in order to maximise revenue from the battery; and
- It does so by managing the battery over the course of a day such that it (a) purchases energy to charge the battery at the lowest cost possible, and (b) manages its discharge from the battery in such a way as to maximise the revenue it receives from the various sources of value available over the course of the day.

More specifically, we have assumed that in each case the community-scale, grid-side battery owner makes money through the following potential sources:

- In the wholesale electricity market through arbitrage – buying electricity to charge the battery as cheaply as possible, and selling energy back into the wholesale market at the highest possible daily price;
- In the ancillary services market through the provision of regulation FCAS (raise and lower) and contingency FCAS (6-second, 60-second and 5-minute response times);

- In network applications through:
    - network support tariffs (where and when these are available from the local DNSP for demand-side services that reduce congestion in the local area network);
    - avoided TUoS charges (where they are included in the distribution tariff); and
    - voltage management (by using the battery as a load at times when PV export would otherwise be high, resulting in voltage issues and throttling back of PV export).

The models differ, however, with respect to how much of the overall revenue that can be generated from the operation of the battery may need to be shared with other counterparties.

It is important to note that none of the grid-side, community-scale ownership models, as we have conceptualised them, respond to retail electricity prices. None of these models is seeking to provide a service where end-customers use the grid-side battery in much the same way they would use a behind-the-meter battery; that is, to arbitrage retail electricity prices either with or without injections from an on-site PV system[6]. Under the current regulatory and metering arrangements, providing that sort of service would encounter a number of challenges including the fact that energy being consumed from the community-scale battery would be subject to the prevailing network tariff. Given that these remain primarily volumetrically based, this would (a) significantly reduce the benefit that an end customer could obtain from the wholesale electricity price arbitrage achieved by the battery, and (b) would provide no financial benefit whatsoever to the battery owner.[7] In addition, there would need to some means for measuring the amount (and possibly the timing) of electricity sent to and re-consumed from the community battery by each end-use customer. [8]

As a proxy for this use of the community battery we have assessed the degree to which the economies of scale of a community battery – if available to an individual end customer -- would improve the financial attractiveness of battery storage. This assessment provides an estimate of the maximum benefit a community-scale, grid-side battery could provide to an end-use customer in terms of its direct impacts on the customer's electricity bill.

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[6] Notwithstanding this, we have undertaken some high-level modelling of this alternative conceptualisation of the business model, applying a number of general assumptions.

[7] If network tariffs were not primarily volumetrically based, or if a special network tariff were available that reflected the fact that the electricity being consumed from the battery only was only using the portion of the network between the battery and the end consumer, such a transaction would be more financially attractive. This study was undertaken to assess and compare the financial attractiveness of a community-scale battery under different ownership models and that of individual household (i.e., behind-the-meter) batteries based on current retail prices and network tariffs.

[8] We are aware that Western Power (in conjunction with Synergy, a retailer) is offering end consumers the use of a community battery on a subscription fee basis as an alternative to metering the electricity flows to and from the consumer and the battery. Under the plan, which is currently being trialled, the consumer gets access to between 6 and 8kWh of virtual storage in the community battery at a cost of $1.00 to $1.90 per day. Presumably, the revenue from the subscription fees paid by the customers reduces the revenue requirement Western Power recovers through its DUoS tariffs. However, despite the fact that Western Power has reported that 95% of the participating customers have "saved money on their power bills", the fact that those customers have saved money does not mean that the subscription service is priced in a way that does not involve a cross-subsidy from non-PV customers.

We are also aware that a Rule change proposal is being considered that would all sub-metering that could be used to avoid DUoS charges being applied to both the electricity going into and out of the community battery. We do not know the details of this possible Rule change proposal, but we note that it is likely that network charges that reflect the costs associated with the voltage level at which electricity that is being exported OR consumed by the community battery and associated end consumers would potentially address the same objective.

2.1. Network-related party ownership

A network-related party is an arms-length subsidiary of the network business. For the purpose of this modelling we have assumed that the network-related party that owns and operates the community-scale battery is a subsidiary of the local DNSP, but this would not necessarily need to be the case.

The network-related party would seek to maximise the revenues from all possible value streams and could potentially deliver non-monetised benefits to the local network provider (for example, any network augmentation benefits for which a price signal is not provided, or a regulatory mechanism is not applied).

We have assumed, for the purposes of the modelling, that the network-related party does not operate in the wholesale market directly, and hence, has to offer something akin to a tolling service to a retailer (who does operate in the wholesale market).[9] This means that they must share some of the financial benefits accruing from the operation of the battery, with the retailer.

2.2. Retailer ownership

A retailer could own the community battery and participate in each of the markets and applications described above. The key difference in this model is that the retailer is assumed to be able to operate directly in the wholesale market, and hence, does not need to enter into any other contractual arrangement with any other counterparty in order to facilitate the provision of the services that come from the battery.

2.3. Community not-for-profit ownership

A community group could own the battery and provide ownership shares to end consumers in the community. These end consumers would share in the profits generated by the ability of the grid-side community-scale battery to access and earn revenue from the various value streams.

Similar to a network-related party, we have assumed that the community not-for -profit group does not operate in the wholesale market directly, and hence, has to offer something akin to a tolling service to a retailer (who does operate in the wholesale market). This means that they must share some of the financial benefits accruing from the operation of the battery, with the retailer.

However, we have also assumed that unlike other ownership models, the community not-for-profit group is able to monetise the benefit that the battery provides for voltage management services. This is because the use of the battery is assumed in this case to be able to better manage (over) voltage related impacts on the network which would have otherwise led to some throttling down in PV output by the local DNSP. Implicitly, this assumption assumes that there is a nexus between the local owners and the beneficiaries of the increased PV that is facilitated by the local operation of the battery.[10]

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[9] While the network related party could allow the retailer to use the battery in the wholesale market at no charge, doing so would simply sacrifice a revenue stream that could potentially help defray the capital costs of the battery, thereby reducing the financial attractiveness of the network-related party's investment.

[10] The primary beneficiaries of the use of a battery to absorb excess PV output are the PV owners who can export electricity (and thereby receive FiT payments) that would otherwise be constrained off. To the extent that the amount of export enabled through voltage management was large enough to change wholesale price it could provide a bnefit to all customers within the reference node, but this is unlikely in most cases, and could only be modelled on a case-specific basis.

3. Assessment of financial viability and benefits to consumers

3.1. Overview of the modelling approach

We have relied on two different internal models to support the analysis that is contained in this report. These models will be referred to from here onwards as the:

- "Grid-side battery" model; and
- "Customer-side battery" model.

As the names suggest, the former is used to estimate the magnitude of the financial benefits that would ensue from the construction and installation of a battery in the distribution business' side of the meter. The latter assumes that the customer installs a battery on their side of the meter.

They are discussed in more detail in the following sections of the report.

3.1.1. Grid-side battery

The following table summarises the benefits that are included in the grid-side model, and a description of how we went about modelling those benefits.

Table 1: Benefits of a grid-side battery

Benefit	Description	Modelling approach
Energy market benefits	The battery storage system is assumed to be used to store electricity generated during low-cost periods, to be discharged during high-cost periods.	• We have assumed that the battery operator/software has perfect foresight[11], enabling it to charge when prices are at their lowest and discharge when prices are at their highest. • 2018/19 NEM prices[12] were the basis for the price differential[13]. More specifically, we calculated the average of the lowest 2 hours in each State for each day, as well as the average of the highest 2 hours in each State for each day, with the difference in these average daily high/low prices being multiplied by the battery's assumed daily discharge capacity and by 365 times (i.e., implicitly, the battery is assumed to be charged and discharged daily for energy arbitrage purposes). The financial benefit is adjusted down to reflect an estimate of the battery's assumed efficiency factor (energy losses). • The modelling was done on a State-by-State basis.

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[11] Perfect foresight is a common feature in modelling. It allows least-cost solutions to be identified where, in actual practice, results would be influenced by other factors. Because it is the relativity of the outcomes of the different ownership models that is of interest (more so than their absolute value) the use of a consistent methodology is of value. The alternative would be to apply a discount factor representing the degree to which actual outcomes depart from perfect foresight. This would require a judgement call, and where the same discount factor was applied to each of the ownership models, the relativity of the results would not change. If different discount factors were to be applied, the results would be a function of a judgementally selected input.

[12] A single year as compared to a range of years was used due to the resources available for the study.

[13] To be clear, we have not attempted to forecast any prices, price ranges or costs, in the modelling. The modelling is in effect a "snapshot" in time. Clearly, any financial analysis undertaken by a proponent is likely to involve them forecasting what wholesale energy prices might be in a prospective market over the life of a battery; what FCAS prices might be etc, as these can change over time depending on the supply/demand balance in that market, and in turn, affect the financial viability of any investment in battery storage.

Benefit	Description	Modelling approach
FCAS market benefits	The battery storage system is assumed to be used to provide frequency control and ancillary services (FCAS). There are two broad types of FCAS services: Regulation FCAS (raise and lower) and Contingency FCAS (6 second, 60-second and 5-minute response times)	• We have assumed that the battery operator/software has perfect foresight, enabling it to provide certain FCAS services when their prices are highest. • 2018/19 NEM prices for each FCAS service in each State were the basis for the prices that the battery operator was assumed to be able to reap from the operation of the battery. • The battery operator is assumed to only provide regulation raise and lower services, as well as the 6-second contingency raise service, as these either: (a) exhibited the highest prices in the 2018/19 dataset; and/or (b) align with the services expected to be provided by battery storage systems (in particular, the response time of batteries is well suited to the 6 second contingency raise service). • We have assumed that either (a) the provision of FCAS services aligns with when the battery would have been used to provide energy arbitrage services (thus adding no incremental cost OR incremental discharges), or (b) that the cost of the energy required to be purchased to provide the FCAS service is the same as what it would be sold for (hence not adding any cost, but adding additional discharges, which has been broadly reflected in the assumed lifespan of the battery).
Transmission benefits[14]	Benefits to the transmission network on the assumption that the battery can assist in alleviating transmission constraints when the transmission network is peaking to be exporting	The benefit to the transmission network is based on the average TUoS locational price published by the relevant transmission network (and AEMO for the Victorian transmission network). This locational price is assumed to be cost-reflective, and therefore, the most appropriate basis for determining the value of network-support to the transmission business. The battery operator is assumed to have perfect foresight as to when these peaks occur, the peaks are assumed to last 2 hours and are assumed to coincide with when wholesale market prices are at their highest (hence the same discharge provides both network support and energy arbitrage benefits). The battery is assumed to be fully discharged over that period in order to provide network support services to the transmission business (and concurrently, to be exporting when wholesale prices are at their highest).

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[14] It is important to note that to defer a transmission or distribution business' future network augmentation *in practice*, the energy storage device needs to inject energy downstream of that part of the network that is faced with congestion (i.e., demand approaching or exceeding supply). This means that the financial benefits of an energy storage device will in practice be a function of the specific location of the device (whether it is located in a part of the network that is congested, and in which higher avoided TUoS payments could be assumed), and the specific part of the network that it injects energy into (for example, which side of the transformer).

Benefit	Description	Modelling approach
Distribution system benefits[15]	The battery is assumed to be able to inject energy into the distribution network at times when that network is peaking, thus assisting the distribution business in managing peak demand constraints on its network and in turn reducing its future augmentation costs.	The benefit to distribution businesses was approximated based on the published LRMC of one DNSP within each State (where such information was available), adjusted to reflect the assumption that the location of the battery will mean that it will not displace energy in the LV network, rather, that it will displace energy at the zone substation. Similar to the assumption adopted for transmission benefits, the battery operator is assumed to have perfect foresight as to when these peaks occur, the peaks are assumed to last 2 hours and are assumed to coincide with when wholesale market prices are at their highest (hence the same discharge provides both network support and energy arbitrage benefits). The battery is assumed to be fully discharged over that period in order to provide network support services to the distribution business.
Voltage benefits	The combination of high levels of PV output and low levels of underlying demand can cause over-voltage excursions on the distribution network. This is generally managed through a PV system's inverter settings, which would lead to the throttling back (or off) of the PV system when certain voltage thresholds are reached on the network.	Voltage issues are assumed to be related to: (a) underlying PV saturation levels, namely, the higher the saturation level, the more likely PV export will cause voltage issues; (b) "abnormally high" output levels from those in situ PV systems (e.g., due to high solar irradiance, no cloud cover etc); and (c) mild temperature conditions, as this is likely to lead to low underlying loads on the network due to the absence of temperature-sensitive loads such as air-conditioners, thereby increasing export. We analysed AEMO information related to the amount of energy that has historically been generated from PV systems in Victoria (over the last approximately 15 years)[18] (reported as a percentage of its nameplate rating) to determine POE levels for PV output that also coincided with a mild temperature day (defined as being between 17 and 24 degrees). We then assumed that at high penetration levels (40%or 50%), discharge from PV systems would have been constrained back to levels similar to a 30% penetration level in order to manage voltage issues on those mild days. We then estimated the amount of energy that would have been constrained, and, based on average wholesale electricity prices in the middle of the day (which is when voltage issues tend to occur), we estimated the value of that energy. This was used as the basis for determining the voltage benefit provided by a grid-side battery.

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[15] As above. It is also worth noting that while the actual benefits from distribution augmentation will vary from area to area and from time to time, meaning that the returns to specific community-scale battery projects will vary significantly, this more global analysis commissioned in this project could only be undertaken on an average basis.

[18] Whilst this relationship between temperature and PV output will differ across States, the use of Victorian data reflects the fact that this was the only information we had available

Benefit	Description	Modelling approach
	The grid-side battery is assumed to be able to facilitate increased production from local PV facilities during these periods by providing a means of storing energy locally[16] (in essence, acting as a solar export sponge and increasing the load on the grid) in order to manage voltage excursions.[17]	

Further to the above, we have made the following cost/sizing assumptions.

Table 2: Key assumptions underpinning grid-side battery – LV connected

Assumption	Value
Cost of battery (LV connected)	$800 / kWh
Size of battery (LV connected)	Peak discharge (kW) = 500kW[19] Usable energy (kWh) = 1,000kWh
Round trip efficiency	90%
Life	3,600 cycles or 10 years.
Degradation of battery	None assumed in the modelling[20]

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[16] We recognise that the ability of a grid-side battery to manage voltage varies with the location of the battery. Using the same discounted value to represent the fact that some batteries would have more or less impact in this regard would change the absolute value of the benefits produced by the different ownership models but not their relativity. Further we do not see any reason to believe that any of the ownership models would consistently result in better or worse battery locations from the perspective voltage control.

[17] Note that the primary benefit in this case is the ability to store PV-generated electricity for later use or sale that would otherwise be curtailed by the network as means for controlling voltage. Under the present regulatory framework, networks are required to manage voltage levels, but are not currently required to allow export that would create voltage level issues. The least-cost means for managing voltage in the face of excess PV export is curtailment. Any network expenditure to manage voltage excursions that result from PV export would be funded by all network customers and therefore would need to be shown to provide other customer benefits (for example, potential reductions in wholesale electricity price) that would offset those costs.

[19] We note that community-scale and other grid-side batteries could be significantly smaller than this. However, to the extent that batteries in these size ranges exhibit scale economies, the financial returns for smaller batteries are likely to be less attractive. This does not mean that a smaller battery would never be the better choice – that will depend on o number of other factors. But, everything else being equal, a larger battery characterised by scale economies will provide a better financial return.

[20] As this is consistently applied across ownership types it will not alter the relativity of outcomes between ownership types.

Assumption	Value
Network charges levied on the battery	We assume that the operation of the battery itself does not lead it to incur network-related charges - rather, it is the end consumer of the energy that comes from the battery that is liable for those charges.
Weighted Average Cost of Capital	4.38% - based on recent information provided by a regulated electricity distribution business.

Table 3: Key assumptions underpinning grid-side battery – HV connected

Assumption	Value
Cost of battery (HV connected)	$700 / kWh
Size of battery (HV connected)	Peak discharge (kW) = 5,000kW[21] Usable energy (kWh) = 10,000kWh
Round trip efficiency	90%
Life	3,600 cycles or 10 years.
Degradation of battery	None assumed in the modelling[22]
Network charges levied on the battery	We assume that the operation of the battery itself does not lead it to incur network-related charges - rather, it is the end consumer of the energy that comes from the battery that is liable for those charges.
Weighted Average Cost of Capital	4.38% - based on recent information provided by a regulated electricity distribution business.[23]

3.1.2. Customer-side battery

In relation to the customer-side battery, the model estimates the number of hours during which the selected battery would be charged and discharged assuming:

- The customer has a solar PV system; and

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[21] As noted above, a larger battery generally enjoys scale economies as compared to a smaller one. We modelled this size battery because an HV connection allows a battery with this capacity to be connected.

[22] As this is consistently applied across ownership types it will not alter the relativity of outcomes between ownership types.

[23] This use of a network cost of capital was chosen for its convenience as a value from a documented source. It is unlikely that any of the other types of owners would have a lower cost of capital than this, so the analyses for them may overstate net benefits in proportion to the difference between the WACC used in this analysis and the actual cost of capital to that type of owner.

- The customer operates the battery passively[24] (i.e., the charge/discharge patterns are simply a function of the customer's load profile and the generation profile from the PV system).

The model has the ability to include a small selection of different tariff structures to determine the financial benefit accruing from a customer's investment in a battery storage system, however, for the purposes of the analysis, we have assumed a simple two-rate tariff (i.e., static time-of-use tariff) in combination with a feed-in tariff for solar PV.

For the avoidance of doubt, the financial benefit modelled is incremental to the benefit assumed to be already derived by a customer from owning a solar PV system. Therefore, it in effect also has regard for the amount of revenue "lost" by the owner of the PV system as a result of using excess PV energy to charge their battery instead of it being exported back into the grid. This (loss in revenue) is obviously offset by the reduction in retail bills that occur as a result of the discharge of the battery, in lieu of relying on grid-supplied energy.

All revenue is offset against the upfront cost of investing in the battery itself, but not the solar PV system.

Other key assumptions are outlined in the table below.

Table 4: Key assumptions underpinning customer-side battery

Assumption	**Assumption**
Cost of battery	$13,725
Size of battery	Peak discharge (kW) = 7kW Usable energy (kWh) = 13.5kWh
Assumed size of existing PV system	5KW
Round trip efficiency of battery	90%
Life	3600 cycles or 10 years.
Retail prices[25]	Peak rate = $0.30/kWh - 7am to 11pm Off peak = $0.15/kWh - 11pm - 7am Solar export = $0.12/kWh - Anytime[26]

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[24] For the avoidance of doubt, this assumes that the customer is only responding to retail electricity prices and feed-in tariffs when making its investment decision. It may be that an individual customer is either (a) able to actively respond to more complex retail price signals by adjusting their consumption behaviour and mix of PV generation / battery usage, OR (b) respond to wholesale price signals, via a Reposit Power type of arrangement.

[25] These are based on what we understand to be a reasonable range of peak/off peak rates available. Obviously, these will differ depending on the state the customer is located in (and even the particular distribution network within the state that they are served by), as well as whether or not they are on a market rate or a rate equivalent to the default market offer. Finally, the underlying economics will be further affected if a customer was to be on another type of tariff structure (e.g., a time of use rate; a demand tariff etc).

[26] This is equivalent to the FiT tariff that was approved by the ESC to apply in Victoria. Other States have FiT tariffs that range from around 8c/kWh (QLD regional areas) through to around 12c/kWh (market-based rates applying in SA).

Assumption	Assumption
PV generation profiles	Generic PV generation profile related to NSW[27]
Load profile	OGW estimate based on a residential customer in Victoria[28]
Weighted Average Cost of Capital	4.38% - based on recent information provided by a regulated electricity distribution business.

3.2. Technical inputs

Three battery electrical storage systems (BESS) were considered in the analysis:

- Behind-the-meter home storage system connected at the 240V 1 phase system
- A grid/community BESS connected at the 415V 3 phase distribution system
- A grid/utility BESS connected at the 11kV 3 phase distribution system.

The inputs into the modelling have come from a review of projects and databases that are operational or currently under development in Australia. While we recognise that there are number of solutions possible, OGW has selected one option for the modelling inputs to define the capital and operating parameters.

Grid-based battery installations are still relatively immature in Australia with only 242MW (310MWh) installed or committed in the NEM across six projects with the majority in SA and VIC[29]. As a result, details on performance and capital costs are disparate and not well established, making it sometimes difficult to separate the facts from hearsay evidence. Table 5 provides a list of project details and sources that were used to inform the technical inputs and costs used in the modelling.

Table 5: Current key projects in Australia examined to determine model inputs.

Installation	Capacity (MW)	Storage (MWh)	Project Status	BESS OEM
Ballarat Energy Storage System	30	30	In Service	Fluence
Bulgana Green Power Hub - BESS	20	34	Committed	Tesla
Dalrymple BESS	30	8	In Service	
Gannawarra Energy Storage System	25	50	In Commissioning	Tesla
Hornsdale Power Reserve Unit 1	100	122	In Service	Tesla
Kennedy Energy Park - Phase 1 - Storage	2	4	Committed*	Tesla

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[27] Note that we have the ability to test the impact of applying different PV generation profiles, however, due to the underlying lack of financial viability of this model, we have not at this stage modelled results at a state-by-state level. [

[28] Similar to the above, we have adopted information based on a Victorian residential customer of average size. At the time of writing, we have modelled results using state-specific inputs.

[29] AEMO, Generator Information, 14/11/19.

Installation	Capacity (MW)	Storage (MWh)	Project Status	BESS OEM
Lake Bonney BESS1	25	52	Committed	Tesla
Lincoln Gap Wind Farm - BESS	10	10	Committed	Fluence

The other key grid-based project that is relevant to this study is the PowerBank community battery storage facility developed by Synergy and Western Power in Meadow Springs, Mandurah, WA. The region has the second highest rooftop PV penetration. This is a first of its kind trial to integrate bulk solar battery storage into the existing grid that also provides customers with a retail storage option. It was launched in late 2018 and allows the 52 residential participants to store up to 8kWh of solar storage a day and then access it after 3pm for a $1 per day charge.

The project is a 105 kW (420kWh) Tesla battery that is integrated into the power network. It is assumed that it has been connected to the 415V network. There are some media reports that the total cost is in order of $200,000 but OGW has discounted these as they are unconfirmed and likely to be derived from the USD costs/kWh without taking into account the exchange rate.

For both the residential behind the meter BESS and the grid-connected BESS the model inputs are based on the Tesla Powerwall 2.0 (residential) and the Tesla Powerpack (grid). The reason is that a reasonable amount of information and analysis is available in the public domain and Tesla maintains a very high public profile in both the residential and utility/grid sectors. The battery systems are modular in specification.

A single size battery has been assumed for each of the different scenarios with a nominal 2-hourr storage capacity for each application (similar storage capacity) with an operational focus on smoothing rooftop solar PV generation.

Table 6: BESS technical assumptions

Connection	Continuous rating (kW)	Storage (kWh)	Round Trip Efficiency (%)	Life – Warranty (years)	Number of cycles/storage capacity
Residential	5	13.5	90%	10	37,800 kWh warranted 1 cycle p/d
Grid 415V	500	1000	88%	10	80% DoD, 6000-8000 cycles
Grid 11kV	5000	10000	88%	10	80% DoD, 6000-8000 cycles

The performance data for the Tesla Powerpack is not available publicly due to the fact that both the performance curve and warranty details are commercially sensitive[30]. It is understood that the battery technology used by Tesla in the Powerpack is manganese cobalt oxide (NMC) cells, which will have a longer cycle life[31],

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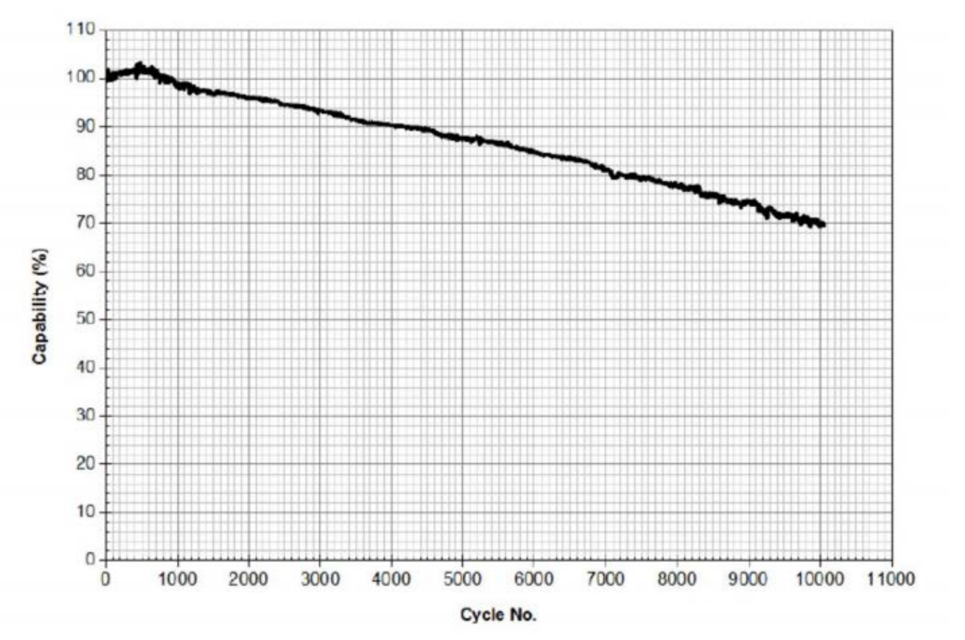
[30] Independent Review of Lithium Ion Battery Lives, Jacobs, 2017.

[31] https://fortune.com/2015/05/18/tesla-grid-batteries-chemistry/

Typical life cycle performance of NMC cells are shown in Figure 1. The performance of NMC and Li Ion batteries also undergo calendar aging. This comprises all aging processes that lead to a degradation of a battery cell independent of charge/discharge cycling and is an important factor in situations where the operational periods are shorter than the idle periods. It has been found that calendar aging can be more predominant in cycle aging studies when cycle depths and current rates are low. The assumption in this analysis is that this is less of an impact due to the daily cycling used for managing excess solar with additional potential dispatch for other ancillary services.

Figure 1: Cycle Life Performance for a typical NMC Battery Cell charged and discharged (at 1C/1C) to 80% DoD, 23±3˚ C



3.3. Cost inputs

The residential Tesla Powerwall 2.0 costs are transparent and publicly known and relatively fixed. The current capital cost (as at 25 July 2019) is $11,700 including the Tesla gateway which provides energy management and monitoring functions for the Powerwall system. The installation costs have been shown to be between $1150 to $2900[32]. It has been assumed the battery installed cost is $13,750 (1,017 $/kWh) and is in broad agreeance with data shown in Figure 2.

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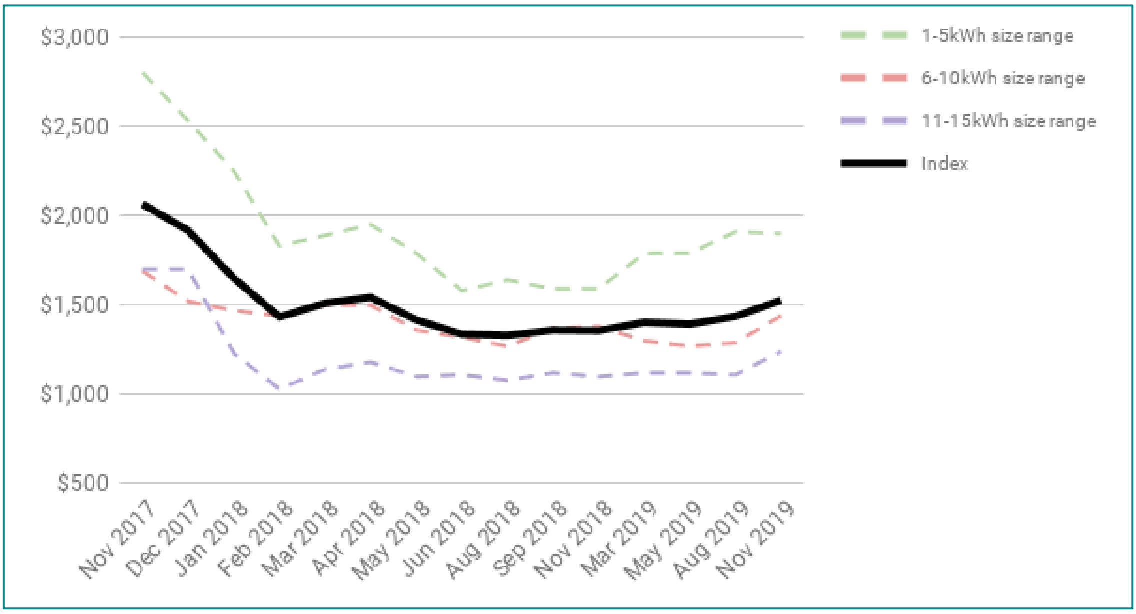
[32] Solar Battery Storage Comparison Table, Solar Quotes. https://www.solarquotes.com.au/battery-storage/comparison-table/

Figure 2: Average price of installed battery systems $/kWh



The cost inputs have been derived from publicly available project information where available and Lazard's storage analysis[33]. Table 7 shows the grid-based storage capital costs.

Table 7: Australian grid-based storage cost assumptions.

Installation	Capacity (MW)	Storage (MWh)	Capex	$/kWh
Ballarat Energy Storage System	30	30	19.93	664
Bulgana Green Power Hub - BESS	20	34	350	
Dalrymple BESS	30	8		
Gannawarra Energy Storage System	25	50	41.19	824
Hornsdale Power Reserve Unit 1	100	122	90	738
Kennedy Energy Park - Phase 1 - Storage	2	4	160	
Lake Bonney BESS1	25	52	41.6	800
Lincoln Gap Wind Farm - BESS	10	10		

Lazard's provides a number of illustrated example projects in the Australian context. The nominated scenarios included an adjacent solar PV but that has been removed in the data shown in Table 8.

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[33] Lazard's levelised cost of storage analysis V4.0, Lazard, Nov 2018.

Table 8: Lazard's Storage Analysis 4.0 – Australian installation examples.

Installation	Utility	C & I
Cost ($/kWh)	489	1092
Capacity (MW)	20	0.5
Storage capacity (MWh)	80	2
EPC %	17%	27%
Storage module %	72%	47%
Inverter %	4%	8%
BOP %	8%	18%

Note: The BOP includes items like housing, controls, thermal management, and fire suppression.

Based on these sources OGW's cost assumptions for the modelling are shown in Table 9. The residential costs, as mentioned previously, are transparent and publicly available. The Grid 415V system has been assumed to be between Lazard's C&I case and the general average of the utility-based projects given the likely higher proportion of EPC and BOP costs to smaller projects.

OGW has assumed the Grid 11kV is similar in cost to the utility-based projects in broad terms and finds the Lazard's Utility cost significantly lower than the current published costs.

Table 9: OGW model base case capital assumptions.

Installation	Cost ($/kWh)
Residential 240V	1,017
Grid 415V	850
Grid 11kV	700

3.4. Results

3.4.1. HV Connected grid-side battery

The following tables summarise the results of the analysis under each ownership model for South Australia, assuming an HV connection[34].

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[34] Results for other States are available in Appendix A.

Table 10: Results – DNSP-Related Party, HV -connected, grid-side battery

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital cost
Energy arbitrage	$5,008,186	$5,008,186	Tolling arrangement with a retailer (80/20)
Distribution system	$1,661,649	$-	Export tariff leads to related party retaining benefit
Transmission system	$454,876	$454,876	Avoided TUoS
FCAS	$1,582,939	$1,582,939	Tolling arrangement with a retailer
Voltage	$-	$-	Accrues to customers with rooftop PV if, in the absence of the grid-side battery, the DNSP would manage voltage by curtailing PV export
Net Benefit/Cost	**$1,707,650**	**$46,002**	

*All results are in NPV terms, over 10 years.

As shown in Table 10, where an Export Tariff[35] has been put in place by the DNSP the related party, as the owner of the asset, will accrue the value of this price signal. There would be no prima facie case for the DNSP related party to share this benefit with end customers.

Table 11: Results – Community-owned, HV-connected, grid-side battery

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital Cost
Energy arbitrage	$5,008,186	$5,008,186	Tolling arrangement with a retailer (80/20)
Distribution system	$1,661,649	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to community owners of battery.
Transmission system	$454,876	$454,876	Avoided TUoS

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[35] The term 'Export Tariff' means a tariff offered by the DNSP that signals the impact that electricity exported to the grid will have on the network's forward-looking costs. For example it would signal each of the following (a) the cost savings that a battery can provide in the form of reducing export at the time of network congestion in the local network area (either in the form of a high export price or a rebate for avoided export), and (b) the cost savings that a battery can provide by exporting electricity at times when congestion in an upstream portion of the network would otherwise reduce the availability of supply to meet aggregate consumer demand within the local network area.

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
FCAS	$1,582,939	$1,582,939	Tolling arrangement with a retailer (assumed 80/20)
Voltage	$15,579	$15,579	Accrues to community owners via increased export capacity
Net Benefit/Cost	**$1,723,230**	**$61,581**	

*All results are in NPV terms, over 10 years.

As shown in Table 11, where an Export Tariff has been put in place by the DNSP, the community-owned battery will accrue the value of this price signal. It would seem likely to assume that it would share this benefit with community members. This sharing could take a number of different forms and could be allocated to members of the community in a variety of ways.

Table 12: Results – Retailer owned, HV-connected, grid-side battery

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital Cost
Energy arbitrage	$6,260,233	$6,260,233	Full financial benefit captured by retailer as compared to other business models
Distribution system	$1,661,649	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to retailer.
Transmission system	$454,876	$454,876	Avoided TUoS
FCAS	$1,978,674	$1,978,674	Full financial benefit captured by retailer
Voltage	$-	$-	Assumes no benefit, as retailer could have procured lost energy from the wholesale market at the same price
Net Benefit/Cost	**$3,355,432**	**$1,693,783**	

*All results are in NPV terms, over 10 years.

As shown in Table 12, where an Export Tariff has been put in place by the DNSP the retailer, as the owner of the asset, will accrue the value of this price signal. There would be no prima facie case for the retailer to share this benefit with end customers if the battery was seen by the retailer as simply an asset for generating wholesale market revenue or providing supply for retail customers in the area served by the battery. However, if the retailer saw the battery as (at least in part) a means for differentiating itself or delivering an added source of value to end customers, and thereby retaining or growing market share, it might be motivated to share a portion of this benefit with its customers in the area served by the community-scale battery.

3.4.2. LV connected grid-side battery

The following tables summarises the results of the analysis under each business model for South Australia, assuming an LV connection[36].

Please note that the ability of the battery owner to obtain the benefits associated with the presence of an Export Tariff – and its likelihood and rationale for sharing those benefits with end-customers – would be essentially the same as in the case of an HV-connected battery.

Table 13: Results – DNSP-Related Party – LV-connected, grid-side battery

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital cost
Energy arbitrage	$500,819	$500,819	Tolling arrangement with a retailer (80/20)
Distribution system	$253,401	$-	Export tariff leads to related party retaining benefit
Transmission system	$45,488	$45,488	Avoided TUoS
FCAS	$158,294	$158,294	Tolling arrangement with a retailer
Voltage	$-	$-	Accrues to customers with a home battery or rooftop PV if, in the absence of the grid-side battery, the DNSP would manage voltage by curtailing export
Net Benefit/Cost	**$158,002**	**-$95,400**	

*All results are in NPV terms, over 10 years.

Table 14: Results – Community-owned, LV-connected, grid-side battery

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital Cost
Energy arbitrage	$500,819	$500,819	Tolling arrangement with a retailer (80/20)
Distribution system	$253,401	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to community owners of battery.
Transmission system	$45,488	$45,488	Avoided TUoS

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[36] Results for other States are available in Appendix A.

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
FCAS	$158,294	$158,294	Tolling arrangement with a retailer (assumed 80/20)
Voltage	$15,579	$15,579	Accrues to community owners via increased export capacity
Net Benefit/Cost	**$173,581**	**-$79,820**	

*All results are in NPV terms, over 10 years.

Table 15: Results – Retailer owned LV-connected, grid-side battery

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital Cost
Energy arbitrage	$626,023	$626,023	Full financial benefit captured by retailer as compared to other business models
Distribution system	$253,401	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to retailer.
Transmission system	$45,488	$45,488	Avoided TUoS
FCAS	$197,867	$197,867	Full financial benefit captured by retailer
Voltage	$-	$-	Assumes no benefit, as retailer could have procured lost energy from the wholesale market at the same price
Net Benefit/Cost	**$322,780**	**$69,378**	

*All results are in NPV terms, over 10 years.

3.4.3. Individual customer behind-the-meter battery

In comparison to the grid-side battery storage system, an individual customer investing in a behind-the-meter battery would be significantly out of pocket based on our assumptions.

Table 16: Results – Individual customer-owned, behind the-meter battery storage system

Cost/Benefit	Individual customer-owned battery storage system
NPV of battery system	-$13,725.00
NPV of incremental benefits (bill reductions)	$2,188.41
Net Benefit/Cost per 13.5kWh system	**-$11,536.59**

*All results are in NPV terms, over 10 years. Assumes the customer responds passively to retail price signals.

In annual terms, the customer would receive a bill reduction benefit of around $250 (this increases to around $350 with a FiT tariff of 9c/kWh instead of the 12c/kWh we have used for modelling).[37] This range is very similar to a recently published quote from a senior solar and battery industry practitioner as to the benefits that he was receiving from his own battery storage system[38].

In addition to the above results, we also tested the impact of applying the economy of scale benefits that appear to be achievable from adopting a grid-scale sized battery in lieu of a individual, smaller scale, behind-the-meter battery, onto an individual customer's financial benefit (one that involves it responding to retail tariffs).

This a reasonable proxy for a community-owned grid-side battery, where the distribution business does not impose network charges on the owners of the battery for the wheeling service required to charge the battery (i.e., it assumes that the energy that is exported from a customer's PV system is wheeled to the battery at no charge).

However, the results indicate that a behind-the-meter battery – even where its cost is reduced to reflect the economies of scale available to a community-scale, grid-size battery – is still not financially attractive to the end customers that may own that battery, for the reasons explained below..

Table 17: Results – Individual customer-owned battery storage system assuming grid-side battery economies of scale benefits

Cost/Benefit	Grid-side battery storage system responding passively to retail prices
NPV of battery system (assuming grid-side economies of scale)	-$10,800.00
NPV of incremental benefits	$2,188.41
Net Benefit/Cost per system	**-$8,611.59**

*All results are in NPV terms, over 10 years. Assumes the customer responds passively to retail price signals and no network charges are applied to energy used to charge/discharge battery

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[37] Although this seems counter-intuitive it should be noted that the higher the FiT, the worse the battery economics are, because the opportunity cost is to the end customer of NOT exporting directly to grid will be higher (i.e., in effect, the cost of the energy going into the battery is higher, the higher the FiT tariff).

[38] https://www.news.com.au/finance/money/check-the-costs-as-battery-energy-storage-sparks-consumer-interest/news-story/51fe2dbb902f1e2cdde95fa6115b31bb

That said, the above does not account for the material level of diversification benefit that may occur if the contributing customers had different load profiles and were on different types of tariffs. We are not in a position to model this; however, we are doubtful that allowing for this would make a grid-side system that responded passively to retail tariffs financially attractive (even assuming no cost to access and use the network).

More generally, the reason for the financial unattractiveness of individual customer-owned batteries (assuming that the battery is operated in a passive way and is responding to retail price signals) as compared to both a grid-side battery as well as a ‘no battery’ option is that the opportunity cost is very high. In particular:

- On the grid-side, the opportunity cost is the fact that the customer does not actively respond to FCAS and wholesale energy prices (amongst other things)[39]; and
- For the individual customer, the opportunity cost is the fact that they export significantly less energy to the grid from their PV systems and hence receive significantly lower FiT payments (because that energy is not being used to charge the battery).

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[39] We note that individually owned batteries organised into a VPP could respond to FCAS price signals. However,

4. Other considerations

4.1. Metering and consumer protection requirements

Under the ownership and operational models assessed in this study, no additional metering would be required for end customers, though the community battery would require revenue-grade metering for both its purchases of electricity from the grid, and exports to the grid, and any additional metering functionality required to participate in the ancillary services market.

We would not envisage any need for additional consumer protection requirements, as the interaction of the community-scale battery with end-consumers would be limited to only (a) the purchase of electricity exported to the battery by customers with on-site generation (which would presumably be governed by the same requirements that exist for rooftop PV export sales), and/or (b) participation as a shareholder in a community-owned enterprise, for which there are also existing consumer protection arrangements.

4.2. Regulatory context and challenges

The ownership models assessed in this study were selected because they conform with the current regulatory framework.

We have not considered a network-owned model because, under the current Rules, networks are not allowed to participate in the wholesale electricity market, and a significant proportion of the revenues from a community-scale, grid-side battery come from wholesale electricity price arbitrage. For the avoidance of doubt, it should be noted that:

- This does not mean that the network could not own the battery and use it to provide a distribution service, for instance as an alternative to network augmentation for balancing supply and demand within a local network area. However, in such a case, the network could not participate in the sale of electricity to the wholesale market. It could allow a retailer or other registered market participant to use the battery to do so (presumably under specified conditions that ensured the network could continue to use the battery for its distribution service requirements). In such a case, the network would presumably charge the party selling the battery's electricity for the use of the battery. This would essentially reduce the share of the arbitrage revenue realised by the party operating the battery in the wholesale market with that share of the revenue going to the network. The advantage that a network could bring in such a situation would be its potentially lower cost of capital as compared to other parties that could own the battery, which could make applications possible that would otherwise have been marginal.
- The fact that the community-scale grid-side battery is not owned by the network does not mean that it cannot provide network services such as network management and network capex deferral. Those services are provided by the operation of the battery, not its ownership and can be purchased by the network from the battery owner in the same way that network support services are currently purchased by networks through the RIT-D mechanism. The provision of such pricing signals allows the competitive market to provide these services. In such a case, the network might also have space where the battery could be located. That space could be made available to the battery owner on a lease basis.

- A Rule change could be considered to allow the network to participate in the wholesale electricity market, or more narrowly to do so only in the case where the grid-side battery could potentially capitalise on the lower cost of capital the network owner might (or might not) be able to bring to the venture as compared to another party. However, this would potentially also reduce competition for the provision of these and, importantly, other services from the battery because the network would always have the best and earliest access to information on the value of a battery to the network.

We have also not considered a model in which the battery is used as a means for end consumers with rooftop PV to store their excess PV generation for later personal use (in what could be thought of as a 'u-store' application). Under such an arrangement the electricity discharged from the battery to the end customer would still flow through the customer's meter and would be subject to network charges. Under current network tariffs this would erode the benefits of the arrangement. Additional metering to determine the amount and timing of the electricity exported to and consumed from the grid by the customer could be used to provide a network tariff credit but the cost of the metering and its installation would erode the benefits of such a scheme to some extent as compared to private battery ownership.

However, such an arrangement could be put in place by a retailer with its customers in a local area through either of the following approaches:

- The Retailer could contract with enough solar customers in an area to enable enough solar generation to be exported to (broadly) match its customers' consumption requirements. Under this approach, the Retailer would essentially sell that energy back to its own customers at a mutually agreed retail price, which would need to cover the cost of the FiT payment to the solar customer (which is analogous to buying the energy from the wholesale market, except that it has all been bought locally), along with any network costs and retail operating costs etc.
- The Retailer could pay the exporting customer for this energy on a per kWh basis (e.g., a FIT), or they could instead charge a tolling/subscription fee to the customer based on the capacity that the customer has bought (e.g., a take-or-pay to cover the cost of the battery). Under this arrangement, the Retailer would discharge the energy out of the battery back to the customers when they require it, and charge a retail fee that would need to cover (a) the network costs incurred in wheeling the energy back to the customer, plus (b) any costs from the wholesale market needed to meet customers' demand; and (c) any retail operating costs. The tolling/subscription fee would be charged separately.

Section 3.4.3 explored the potential benefits of an arrangement where the network charges for the re-consumption of stored electricity would not be incurred by the end consumer. This was done by reducing the cost of the battery to the end-consumer to reflect the scale economy in the cost of a community-scale battery. As shown in that section (see particularly Table 16 and Table 17), while this improves the returns to the end-consumer materially (by approximately 25%), it does not make the use of the battery cost-effective.

A related issue is that flows to and from the end user and the community scale battery are subject to network charges in both directions and potentially from the grid to the battery and again from the battery to the end customer (in the case where the battery is charged from the upstream grid). Some parties have proposed that electricity flows between the end-consumer and the community battery be exempt from network charges or some separate DUoS charge. A more cost-reflective alternative would be for all network electricity variable charges to be cost-reflective in terms of the time of the flow and the level of the network involved (and would not include any capital or residual cost recovery). This would reflect the fact that any flow on the network can potentially impose costs on the network and users of the network should bear the costs they impose. Most relevant to the community battery case would be that flows between a grid-side battery and the end consumer would only be charged based on the costs in the local area network – all upstream network costs would be removed from that charge.[40]

4.3. Potential negative impacts and risks

4.3.1. Limited lifespan of batteries

Only Li ion batteries have been investigated in this study given they are used in the majority of the BESS systems commercially deployed in Australia at the residential and utility level.

The lifespan of Li-ion batteries is complicated and depends on the depth of discharge, the age of the BESS and the coulomb rating/rate of discharge. Essentially Li-ion batteries don’t have a finite life but:

- The value of cycle and calendar life is often provided by the manufacturers. These values represent an upper limit of cycles of operation and age of battery by which the battery will reach its End-of-Life with high probability. End of life is defined as a state of the battery when the maximum capacity of the battery reduces to a percentage of its rated initial capacity. The battery is still operational after end-of-life but at a reduced capacity. Calendar life refers to the number of years the battery is expected to last until the battery will reach end of life. It is independent of how much the battery is charged and discharged. However, calendar life is dependent on the state of charge of the battery and the temperature. Cycle life limits the number of cycles of operation a battery could perform before reaching end of life.
- The number of cycles of operation will depend on storage parameters and charging and discharging efficiency losses. Batteries performing more cycles each day would imply the gains per cycle will be lower. In li-ion batteries the growth of a solid-electrolyte inter-phase layer increases the impedance of the battery and therefore reduces the battery capacity because of the consumption of cyclable lithium from the battery.

  In other words, the cyclic degradation is a function of the number of cycles and also the amount of discharge of each cycle which is not linear. Figure 3 shows that the number cycles increases exponentially as the depth of discharge of the cycle decreases.

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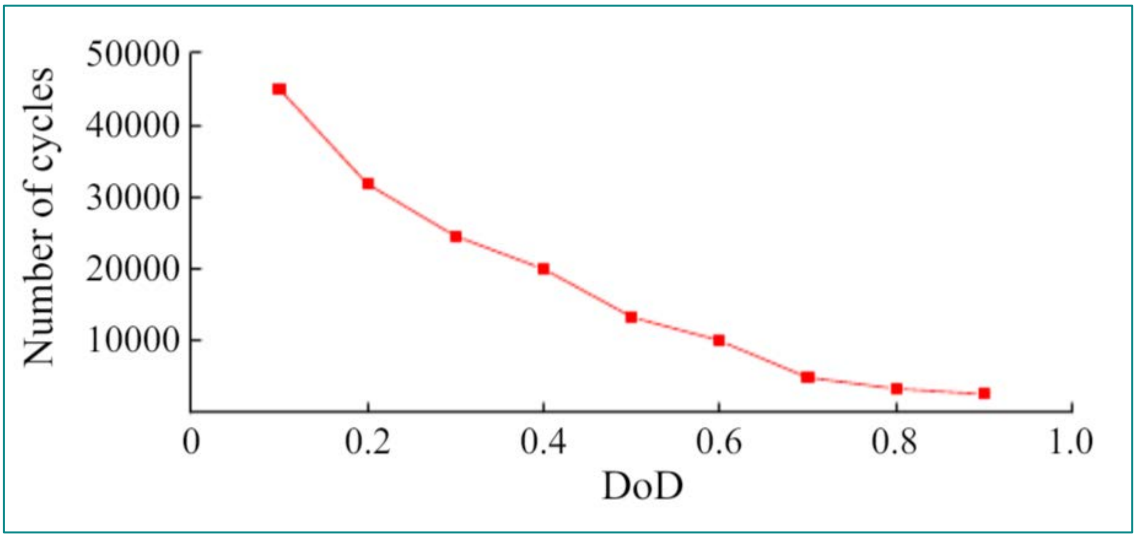
[40] This assumes that the battery is connected to the LV side of the distribution network. Even so, there would remain a possibility that export from the battery would flow to the HV when the it times when there was no net demand in the local network area. It is assumed this would be a rare event and, in any case, could be identified through network metering.

Figure 3: Cycle life versus DoD curve for lithium-ion NMC battery



For the residential application where use is primarily for solar self-consumption, it is unlikely the BESS would exceed its warranty conditions within the 10-year life.

There may be other future scenarios of solar self-consumption with overnight charging for peak demand management that could potentially exceed this operating limit, but in practice it is expected that the settings for grid-based charging would be used sparingly to avoid excessive “solar spill” and therefore would be unlikely to exceed the manufacturer’s operating limits.

It is unlikely that the operating scenarios envisaged will prematurely age the batteries to less than ten years. However, at the end of ten years, the reduced warranted capacity of the battery would mean that the homeowner would likely be exporting greater quantities of solar energy to the grid, so may be economically incentivised to replace the battery at this point.

It is important to remember that the BESS is not “dead” at the end of the 10-year period and will still have a majority of its capacity available for service beyond the warranty period.

The grid application batteries tend be more of an engineered approach compared to the commodity based residential application. It is typical that a specific project-based battery will come with a 10-year product warranty in relation to defects and a 10-year energy retention warranty. As is typical for these types of batteries, this includes a warranted storage capacity curve with a guaranteed minimum at the end of ten years, provided that the aggregate discharge of the battery has not exceeded a certain limit that is within the bespoke contract.

There could be a scenario where the grid-based BESS is used for applications that do require additional cycling such as FCAS applications. While these events and requirements may require additional cycling, the total depth of discharge is relatively small and needs to be considered with these events occurring over seconds to a few minutes. For example, if an event occurred that was 6 minutes duration in which full output was needed, this would equate to only a single cycle event DoD of approximately 5% at full output in a 2-hour storage system. These low depth of discharge cycles have an exponentially lower impact on the life of the battery compared to the load shifting, larger depth of discharge applications. As such, it is unlikely they will impact the operational life of the grid BESS.

4.3.2. Other technical or operating factors

[to be completed]

4.3.3. Competition from home batteries

Individual home batteries do not, in the main, directly compete at the local level with the grid-side, community-scale battery models discussed in this report. In particular, they cannot access and therefore do not eliminate the availability of wholesale market price arbitrage to the grid-side battery, which is a significant portion of the community-scale battery's revenue stream. Similarly, without some form of coordination, home batteries are unlikely to reduce the need for FCAS.

VPPs, however, could provide more competition as they would be more likely to seek to provide FCAS. Their ability to benefit from wholesale market arbitrage is more limited than that of the grid-side models due to the fact that any energy purchased to charge the batteries other than that from local PV systems would incur distribution charges. However, it is likely that a VPP would have higher transaction costs to establish than a grid-scale community owned battery. The costs would include the costs to recruit participants in the VPP, and the cost of the comms and controls required to operate the individual batteries participating in the VPP. Both individual home batteries and VPPs could assist in managing voltage-related issues at the local network level, which could reduce the benefits that a grid-side battery could accrue from that potential revenue stream.

4.3.4. Monopolisation of the market by the networks

We do not consider that this likely to constitute a serious problem. It is true that the local distribution network business is in a uniquely favoured position to know where a grid-side battery could be of particular benefit to the network. It is also the case that networks are free to invest in assets (subject to regulatory approval) that provide a distribution service and are located on the grid side of end consumers meters.

Therefore, to the extent that a grid-side battery could be economically justified for its ability to provide a distribution service, its value could be identified, and it could be owned and operated exclusively by the network business.

However, it is difficult to see why this outcome would be pursued, unless:

- The distribution business' actual weighted average cost of capital (WACC) was significantly below the regulatory WACC (making any capex investment in a regulated service all the more appealing, financially), and/or
- The capex that the distribution business would avoid (as compared to the battery investment) was so large as to make it worthwhile for the distribution business to make the investment in the battery storage system in order to monetise benefits under the capital efficiency sharing scheme (CESS); and/or
- The distribution business considered there to be other, material, non-financial benefits stemming from such an investment (e.g., to be able to promote itself as a facilitator of more distributed solar); and/or

The distribution business did not have a related party service provider that it believed would be able to compete in the battery storage market (hence if it went to market, it would be a third-party provider who owned and operated the storage facility[41]).

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[41] The ability to identify places in the network where a battery could be of value to the network could potentially be seen as an opportunity for the network to favour its own subsidiary party, This potential exists with regard to other services and is covered by established tendering procedures and processes which should mean that all potential providers are treated equally.

5. Conclusions

5.1. Benefits of a grid-side community scale battery as compared to an individually owned, behind the meter battery

All three of the grid-side community scale battery ownership models outperform an individually owned, behind-the-meter battery.

The reason for the financial unattractiveness of individual customer-owned batteries (assuming that the battery is operated in a passive way and is responding to retail price signals) as compared to both a grid-side battery as well as a 'no battery' option is that the opportunity cost is very high. In particular:

- On the grid-side, the opportunity cost is the fact that the customer does not actively respond to FCAS and wholesale energy prices (amongst other things); and
- For the individual customer, the opportunity cost is the fact that they export significantly less energy to the grid from their PV systems and hence receive significantly lower FiT payments for that exported energy (because that energy is not being used to charge the battery).

It is also worth noting that the value that a behind-the-meter battery can provide in terms of retail price arbitrage depends on several factors, the most important being the level of any FiT that is available, the level of the retail variable consumption charge and whether that charge is different at different times of day. As the difference between the level of the FiT and the variable retail charge deceases, so does the value of the behind the meter battery. Both sides of this equation have varied in different directions in different states in recent years.

5.2. Comparative ownership benefits of the three grid-side community scale battery ownership models

The scale of benefits available to the owner of the asset is important as, everything else being equal, the party that has the largest potential returns will be in the best position to out-compete other parties to invest in any particular opportunity to deploy a grid-side battery. It is also the case that a greater level of benefit provides more potential for those benefits to be shared with end consumers. However, the motivation of different types of owners to do so is also likely to vary.

Of the three community-scale ownership models tests, the retailer-owned model produces the highest level of benefit to the asset owner. This is because the retailer can interact directly with the wholesale market, thereby gaining the full benefit available from the wholesale electricity price arbitrage and FCAS revenue streams.

We have assumed that in the other two ownership models the network-related party or the community group will enter into a tolling arrangement with a retailer to gain access to the revenue streams available from the wholesale electricity market and FCAS (or a non-retailer party that is a registered participant in the case of FCAS), and that this will require a split of those revenue stream benefits with the retailer or non-retailer registered FCAS participant.

However, a network-related party or a community group could become a market participant and gain direct access to either or both wholesale market and/or FCAS benefits, but this would involve some costs and entail taking on some responsibilities outside the usual role of those entities. It would seem particularly unlikely for a community group to undertake such a course of action, and it would only make sense for a network-related party if that party was aiming to make the provision of community batteries a significant focus of its business.

With regard to the willingness of the three types of owners to share the benefits or asset owners with customers, it can be safely assumed that the community group owner would be the most likely to do so, and to provide the greatest share of the benefits to end user. The sharing of benefits could take many forms ranging from (a) 'dividend' payments to those community members that have invested in the battery (i.e., that have provided funding for the purchase and/or operation of the battery), to (b) payments/rebates customers whose PV export was provided to the community battery, or (c) investments in assets or services to the community as a whole (e.g., use of the net revenue to fund community events, assets such as a park or play equipment, or services such as sponsored child care).

A retailer owner of a community battery might use some of the net revenue to make payments to its customers within the area whose PV export was provided to the community battery, or to provide an incentive to end-users within the area to become a customer of the retailer. Although the retailer, as discussed above, would be likely to generate a greater absolute level of net revenue that community group owner, the retailer would be likely to want to retain a larger percentage of the net revenue achieved, given it is profit-driven and expected to provide returns to shareholders.

A network-related party would similarly be expected to provide a return to its shareholders. Unless it was also providing some form of direct service to end customers, however, it would not appear to have the same motivation as a retailer to use a share of the net revenue benefit to seek to 'win' or influence end customers.

5.3. Benefits to end consumers

Benefits to end consumers from the grid-side community scale battery ***regardless of the ownership of the battery itself*** include the following:

- For all end consumers in the distribution network, the potential to benefit from lower network tariffs due to the deferral of local network augmentation costs. It is worth noting the magnitude of this benefit remains the same under each type of community-scale battery ownership. However, the ability for the community-scale battery to provide this benefit depends on there being some form of price signal regarding this benefit from the network;
- For all end consumers within the local area served by the grid-side, community scale battery:
  - the potential to consume locally generated, carbon-free electricity (to the extent that the community battery purchases and re-injects rooftop PV electricity generated within the local area that might otherwise have been curtailed due to voltage management by the local network);[42] and
  - the potential to continue to have access to electricity supply (from energy stored in the community-scale battery) during a supply interruption that occurs upstream of the local area (e.g., a generation failure or an upstream network asset failure).
- For end-consumers in an area in which there is a community-owned grid-side battery, the potential to participate as shareholders in the community-scale battery and potentially earn a share of the profits of the battery operation, and/or potentially benefit through other community uses of the profits of the community-owned battery sponsored by the community group.

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[42] Any of the three types of owners could presumably present this non-monetary benefit as part of their community service undertakings.

5.4. Implications for advocacy

The benefits of grid-side, community-scale batteries would appear to be able to be maximised by:

- Ensuring that cost-reflective price signals are available for the services that these devices can provide in deferring or reducing the need for augmentation to the network. This will maximise the potential benefit of the services available from these devices, and
- Arranging means to make it easier for a community-owned battery (as the ownership type that is most likely to pass on any benefit generated to end consumers) to gain access to other revenue streams that are currently only available to market participants (i.e., wholesale energy price, FCAS and potentially any new price signals that may be put in place for system security and/or stability). This can most readily be done by allowing non-retailer parties to provide services in these markets. This has already been done in several instances, examples being the ability of Small Generator Aggregators to bid into the wholesale electricity market and DR Aggregators to provide ancillary services. Any arrangement that expands the avenues through which a community battery can gain access to the wholesale and ancillary services markets will increase competition for the service that this asset can provide and therefore should be expected to increase returns to the community group owning the asset, and to these respective markets, thereby increasing the total benefit to be provided.

Appendix A: Results for grid-side battery storage systems in other States

A.1 Victoria

A.1.1 HV Connection

The following tables summarises the results of the analysis under each business model for Victoria, assuming a HV connection.

Table 18: Results – DNSP – Related Party

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital cost
Energy arbitrage	$4,417,493	$4,417,493	Tolling arrangement with a retailer (80/20)
Distribution system	$830,824	$-	Export tariff leads to related part retaining benefit; CESS provides for sharing with customers after 5 years of no export tariff
Transmission system	$363,878	$363,878	Avoided TUoS
FCAS	$1,462,730	$1,462,730	Tolling arrangement with a retailer
Voltage	$-	$-	Accrues to customer if alt was to manage via inverters
Net Benefit/Cost	**$74,925**	**-$755,899**	

*All results are in NPV terms, over 10 years.

Table 19: Results – Community owned battery

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital Cost
Energy arbitrage	$4,417,493	$4,417,493	Tolling arrangement with a retailer (80/20)
Distribution system	$830,824	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to community owners of battery.
Transmission system	$363,878	$363,878	Avoided TUoS
FCAS	$1,462,730	$1,462,730	Tolling arrangement with a retailer (assumed 80/20)

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Voltage	$15,762	$15,762	Accrues to community owners via increased export capacity
Net Benefit/Cost	**$90,687**	**-$740,137**	

*All results are in NPV terms, over 10 years.

Table 20: Results – Retailer owned battery

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital Cost
Energy arbitrage	$5,521,866	$5,521,866	Full financial benefit captured by retailer as compared to other business models
Distribution system	$830,824	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to retailer.
Transmission system	$363,878	$363,878	Avoided TUoS
FCAS	$1,828,413	$1,828,413	Full financial benefit captured by retailer
Voltage	$-	$-	Assumed no benefit, as retailer could have procured lost energy from mkt at same price
Net Benefit/Cost	**$1,544,981**	**$714,157**	

*All results are in NPV terms, over 10 years.

A.1.2 LV Connection

The following tables summarises the results of the analysis under each business model for Victoria, assuming a LV connection.

Table 21: Results – DNSP – Related Party

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital cost
Energy arbitrage	$441,749	$441,749	Tolling arrangement with a retailer (80/20)

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Distribution system	$103,853	$-	Export tariff leads to related part retaining benefit; CESS provides for sharing with customers after 5 years of no export tariff
Transmission system	$36,388	$36,388	Avoided TUoS
FCAS	$146,273	$146,273	Tolling arrangement with a retailer
Voltage	$-	$-	Accrues to customer if alt was to manage via inverters
Net Benefit/Cost	**-$71,737**	**-$175,590**	

*All results are in NPV terms, over 10 years.

Table 22: Results – Community owned battery

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital Cost
Energy arbitrage	$441,749	$441,749	Tolling arrangement with a retailer (80/20)
Distribution system	$103,853	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to community owners of battery.
Transmission system	$36,388	$36,388	Avoided TUoS
FCAS	$146,273	$146,273	Tolling arrangement with a retailer (assumed 80/20)
Voltage	$15,762	$15,762	Accrues to community owners via increased export capacity
Net Benefit/Cost	**-$55,975**	**-$159,828**	

*All results are in NPV terms, over 10 years.

Table 23: Results – Retailer owned battery

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital Cost

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Energy arbitrage	$552,187	$552,187	Full financial benefit captured by retailer as compared to other business models
Distribution system	$103,853	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to retailer.
Transmission system	$36,388	$36,388	Avoided TUoS
FCAS	$182,841	$182,841	Full financial benefit captured by retailer
Voltage	$-	$-	Assumed no benefit, as retailer could have procured lost energy from mkt at same price
Net Benefit/Cost	**$75,269**	**-$28,584**	

*All results are in NPV terms, over 10 years.

A.2 NSW

A.2.1 HV Connection

The following tables summarises the results of the analysis under each business model for NSW, assuming a HV connection.

Table 24: Results - DNSP - Related Party

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital cost
Energy arbitrage	$2,243,559	$2,243,559	Tolling arrangement with a retailer (80/20)
Distribution system	$747,742	$-	Export tariff leads to related part retaining benefit; CESS provides for sharing with customers after 5 years of no export tariff
Transmission system	$498,495	$498,495	Avoided TUoS
FCAS	$1,814,409	$1,814,409	Tolling arrangement with a retailer
Voltage	$-	$-	Accrues to customer if alt was to manage via inverters

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Net Benefit/Cost	**-$1,695,795**	**-$2,443,537**	

*All results are in NPV terms, over 10 years.

Table 25: Results - Community owned battery

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital Cost
Energy arbitrage	$2,243,559	$2,243,559	Tolling arrangement with a retailer (80/20)
Distribution system	$747,742	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to community owners of battery.
Transmission system	$498,495	$498,495	Avoided TUoS
FCAS	$1,814,409	$1,814,409	Tolling arrangement with a retailer (assumed 80/20)
Voltage	$14,606	$14,606	Accrues to community owners via increased export capacity
Net Benefit/Cost	**-$1,681,189**	**-$2,428,931**	

*All results are in NPV terms, over 10 years.

Table 26: Results - Retailer owned battery

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital Cost
Energy arbitrage	$2,804,448	$2,804,448	Full financial benefit captured by retailer as compared to other business models
Distribution system	$747,742	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to retailer.
Transmission system	$498,495	$498,495	Avoided TUoS
FCAS	$2,268,012	$2,268,012	Full financial benefit captured by retailer

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Voltage	$-	$-	Assumed no benefit, as retailer could have procured lost energy from mkt at same price
Net Benefit/Cost	**-$681,303**	**-$1,429,045**	

*All results are in NPV terms, over 10 years.

A.2.2 LV Connection

The following tables summarises the results of the analysis under each business model for NSW, assuming a LV connection.

Table 27: Results – DNSP – Related Party

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital cost
Energy arbitrage	$224,356	$224,356	Tolling arrangement with a retailer (80/20)
Distribution system	$116,315	$-	Export tariff leads to related part retaining benefit; CESS provides for sharing with customers after 5 years of no export tariff
Transmission system	$49,849	$49,849	Avoided TUoS
FCAS	$181,441	$181,441	Tolling arrangement with a retailer
Voltage	$-	$-	Accrues to customer if alt was to manage via inverters
Net Benefit/Cost	**-$228,038**	**-$344,354**	

*All results are in NPV terms, over 10 years.

Table 28: Results – Community owned battery

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital Cost
Energy arbitrage	$224,356	$224,356	Tolling arrangement with a retailer (80/20)

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Distribution system	$116,315	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to community owners of battery.
Transmission system	$49,849	$49,849	Avoided TUoS
FCAS	$181,441	$181,441	Tolling arrangement with a retailer (assumed 80/20)
Voltage	$14,606	$14,606	Accrues to community owners via increased export capacity
Net Benefit/Cost	**-$213,432**	**-$329,748**	

*All results are in NPV terms, over 10 years.

Table 29: Results – Retailer owned battery

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital Cost
Energy arbitrage	$280,445	$280,445	Full financial benefit captured by retailer as compared to other business models
Distribution system	$116,315	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to retailer.
Transmission system	$49,849	$49,849	Avoided TUoS
FCAS	$226,801	$226,801	Full financial benefit captured by retailer
Voltage	$-	$-	Assumed no benefit, as retailer could have procured lost energy from mkt at same price
Net Benefit/Cost	**-$126,589**	**-$242,905**	

*All results are in NPV terms, over 10 years.

A.3 QLD

A.3.1 HV Connection

The following tables summarises the results of the analysis under each business model for QLD for a HV connected system, assuming a HV connection.

Table 30: Results – DNSP – Related Party

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital cost
Energy arbitrage	$2,008,208	$2,008,208	Tolling arrangement with a retailer (80/20)
Distribution system	$747,742	$-	Export tariff leads to related part retaining benefit; CESS provides for sharing with customers after 5 years of no export tariff
Transmission system	$498,495	$498,495	Avoided TUoS
FCAS	$2,475,190	$2,475,190	Tolling arrangement with a retailer
Voltage	$-	$-	Accrues to customer if alt was to manage via inverters
Net Benefit/Cost	**-$1,270,365**	**-$2,018,107**	

*All results are in NPV terms, over 10 years.

Table 31: Results – Community owned battery

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital Cost
Energy arbitrage	$2,008,208	$2,008,208	Tolling arrangement with a retailer (80/20)
Distribution system	$747,742	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to community owners of battery.
Transmission system	$498,495	$498,495	Avoided TUoS
FCAS	$2,475,190	$2,475,190	Tolling arrangement with a retailer (assumed 80/20)
Voltage	$12,490	$12,490	Accrues to community owners via increased export capacity

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Net Benefit/Cost	**-$1,257,875**	**-$2,005,617**	

*All results are in NPV terms, over 10 years.

Table 32: Results - Retailer owned battery

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Cost of system	-$7,000,000	-$7,000,000	Capital Cost
Energy arbitrage	$2,510,260	$2,510,260	Full financial benefit captured by retailer as compared to other business models
Distribution system	$747,742	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to retailer.
Transmission system	$498,495	$498,495	Avoided TUoS
FCAS	$3,093,988	$3,093,988	Full financial benefit captured by retailer
Voltage	$-	$-	Assumed no benefit, as retailer could have procured lost energy from mkt at same price
Net Benefit/Cost	**-$149,516**	**-$897,258**	

*All results are in NPV terms, over 10 years.

A.3.2 LV Connection

The following tables summarises the results of the analysis under each business model for QLD for a LV connected system, assuming a HV connection.

Table 33: Results - DNSP - Related Party

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital cost
Energy arbitrage	$200,821	$200,821	Tolling arrangement with a retailer (80/20)

Cost/Benefit	DNSP – Related Party with Export tariffs	DNSP – Related Party without Export tariffs	Commentary
Distribution system	$103,853	$-	Export tariff leads to related part retaining benefit; CESS provides for sharing with customers after 5 years of no export tariff
Transmission system	$49,849	$49,849	Avoided TUoS
FCAS	$247,519	$247,519	Tolling arrangement with a retailer
Voltage	$-	$-	Accrues to customer if alt was to manage via inverters
Net Benefit/Cost	**-$197,958**	**-$301,811**	

*All results are in NPV terms, over 10 years.

Table 34: Results – Community owned battery

Cost/Benefit	Community owned with Export tariffs	Community owned without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital Cost
Energy arbitrage	$200,821	$200,821	Tolling arrangement with a retailer (80/20)
Distribution system	$103,853	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to community owners of battery.
Transmission system	$49,849	$49,849	Avoided TUoS
FCAS	$247,519	$247,519	Tolling arrangement with a retailer (assumed 80/20)
Voltage	$12,490	$12,490	Accrues to community owners via increased export capacity
Net Benefit/Cost	**-$185,467**	**-$289,320**	

*All results are in NPV terms, over 10 years.

Table 35: Results – Retailer owned battery

Cost/Benefit	Retailer owned with Export tariffs	Retailer owned without Export tariffs	Commentary
Cost of system	-$800,000	-$800,000	Capital Cost
Energy arbitrage	$251,026	$251,026	Full financial benefit captured by retailer as compared to other business models
Distribution system	$103,853	$-	If cost-reflective export tariffs provided by DNSP, network benefit flows through to retailer.
Transmission system	$49,849	$49,849	Avoided TUoS
FCAS	$309,399	$309,399	Full financial benefit captured by retailer
Voltage	$-	$-	Assumed no benefit, as retailer could have procured lost energy from mkt at same price
Net Benefit/Cost	**-$85,873**	**-$189,726**	

*All results are in NPV terms, over 10 years.