Attachment 1
to Item 10.3.2.

Community Batteries Cost Benefit Analysis

Date of meeting: 26 November 2024
Location: Council Chambers
Time: 6:30pm

Australian National University

Battery Storage and Grid Integration Program

An initiative of The Australian National University

Community batteries: a cost/benefit analysis

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For more information on the overall project: https://arena.gov.au/projects/community-models-for-deploying-and-operating-distributed-energy-resources/

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Executive Summary

There is growing interest in community batteries in Australia, with several trial projects underway. Battery storage of this scale (100kW-1MW) may offer benefits over household batteries, including lower costs and increased ability to integrate more solar PV energy generation into the distribution network (hosting capacity). Community batteries may also provide an opportunity to increase energy equity, providing an opportunity for a wider range of individuals to access the benefits of renewable resources.

In this report we evaluate the financial viability of community batteries. We calculate the total cost of purchasing and maintaining the battery, compared to battery revenue. We identify five services that can generate revenue for the battery owner/operator (i) customer demand management, (ii) demand management for the distribution network service provider (DNSP) (iii) arbitrage from the spot market (iv) Frequency and Ancillary markets (FCAS) and (v) network support. Maximising the simultaneous value from these revenue streams is essential for the economic viability of storage, but it will also ensure that storage is used to effectively support a reliable and secure future energy grid. The analysis method is demonstrated with a test case of a community battery in the new suburb of Jacka, located in Canberra, ACT, Australia.

Key findings:

- Third party owned community battery models are likely to be financially viable, under current energy and FCAS market prices. To ensure the future economic viability of these models, payments for the network services they provide need to be established.
- A DNSP (or network operator) owned community battery is unlikely to be financially viable without adding a significant proportion of the battery cost to their Revenue Asset Base (RAB).
- A DNSP owned, for-profit battery, could potentially be financially viable under current market conditions, if a significant proportion of the battery was leased to another party for market participation.
- A reduced energy transport network cost for ‘local use of service’ (LUoS) is required to financially motivate charging the battery with locally generated solar energy.

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1 Introduction

Community-scale energy storage (CES) (100kW-5MW) offer benefits over residential and grid-scale energy storage systems. Potential benefits include reduced energy costs for customers, improved solar energy self-consumption, peak shaving, and increased network hosting capacity for non-dispatchable energy generation such as rooftop solar. There is widespread interest in community-scale storage, not just from customers and communities, but from the energy sector more broadly, including distribution network service providers (DNSPs). Community interest in shared storage may in part reflect a broader enthusiasm from customers for a sharing economy.

> A community battery is a specific example of community-scale storage which is either (1) owned by the community, and/or (2) operated for the community (as virtual storage), or (3) operated to benefit the community indirectly (e.g. through profits flowing back).

The potential benefits of community batteries may even increase over time as we increasingly electrify our energy system. Electric vehicles (EVs) and the replacement of gas with electricity for heating and cooking, will lead to increasingly 'peaky' demand which can lead to network congestion. Electric vehicles will on the whole provide valuable 'storage on wheels' but the timing and location of charging and discharging is unpredictable. Therefore, we are faced with both increasing peak load and increasingly unpredictable peak load, as well as increasing peak exports from household solar photovoltaic (PV) generation. Together these challenges could cause demand and voltage management issues for the local DNSP. In many cases, the solution for this type of network congestion is an expensive grid upgrade, because existing legislation does not incentivise or even allow more innovative measures. It is possible that, in the future, EVs could provide the local storage required, if coordination of charging and discharging is well-managed. However, our analysis reveals that community batteries should be explored as a solution for the current challenges posed by increasing rooftop solar generation and electrification of the energy system.

In Australia, several trial CES projects are underway in the state of Western Australia, where DNSPs are state-owned and regulations allow them to buy and sell energy directly to customers, which makes the community battery model straightforward [1], [2]. On the east coast of Australia, regulations governing the National Electricity Market (NEM) do not allow networks to buy and sell energy directly to customers, such that more innovative models for ownership of the community battery will be required. We explore four of those models in this report.

To explore battery ownership models, we first outline the the services community batteries can provide, and estimate the current value of these services to a battery owner. While this research goal was our intention from the outset, our interviews with energy sector professionals confirmed sector interest in detailed modelling to provide a business case for different models of storage [3].

In general, community batteries installed on the LV distribution network and in-front-of-the-meter can be operated to (1) perform demand management for customers, (2) perform demand management for DNSPs, (3) generate revenue from market services (energy arbitrage and FCAS) and (4) provide specific services to network service providers and/or system operators. In this report, demand management refers to peak import/export shaving through the use of community batteries and PV power generation. Energy arbitrage refers to the buying and selling of energy to and from the national electricity market (NEM). FCAS is a market which groups services that help maintain our power system around 50Hz, which requires maintaining the demand/generation balance across the NEM. The FCAS market allows the Australian Electricity Market Operator (AEMO) to send price signals to generators/loads to increase generation/demand when needed. Energy storage is both a generator and a load and therefore can participate in the FCAS market. DNSP services include keeping the low voltage (LV) grid operational during outages or maintenance, network upgrade deferral, congestion relief and ensuring adequacy of supply. As we discuss in Section 4.3, many of these network services have not yet been monetised, as they have until now been provided only by DNSPs themselves.

2 Modelling community battery operation

In this study we estimate the value of the services a community battery can provide, for four different ownership models. The ownership models we investigated were

1. Third party owned community battery
2. Third party owned for-profit model
3. DNSP owned community battery
4. DNSP owned for-profit model

Full details of the ownership models are given in Section 6. Costs were calculated over one year (2018). Our in-house open-source software (c3x) calculates how a community battery would

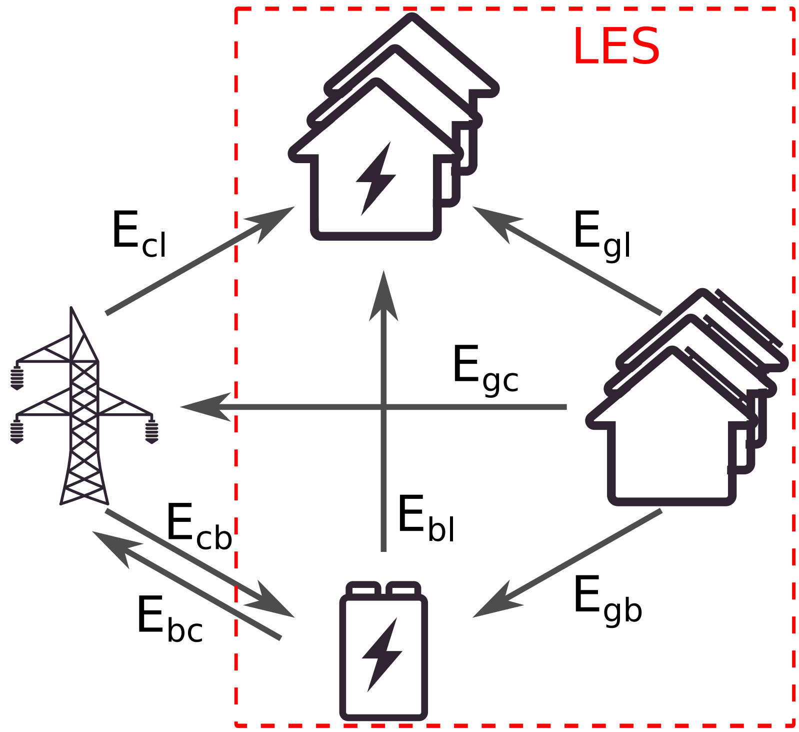


Figure 1: Energy flows for our calculations, where collections of connection points are aggregated together into a group, referred to here as a Local Energy System (LES) with (surplus) net generation of power and another group with net demand for energy. The LES includes community energy storage (CES). Energy flows are: E_{cl} from point of coupling to meet the load, E_{cb} from point of coupling to CES, E_{bc} from CES to point of coupling, E_{bl} from CES to load, E_{gl} from generation to load, E_{gb} from generation to CES, E_{gc} from generation to the point of coupling.

operate, given (i) the battery operation algorithm and (ii) energy demand plus solar generation and (iii) energy prices. We then calculate how the community battery would impact energy flows – and associated costs – between the battery, the grid and customers who have chosen to participate in the battery scheme.

For our battery calculations, we consider a segment of the distribution grid downstream from a distribution substation, which includes a number of houses (connection points) and a community battery, as shown in Fig. 1. All connection points that are net loads are aggregated into one group (shown at the top of Fig. 1). Similarly, all connection points that are net generators are aggregated together (right side of Fig. 1), and thirdly, connection points that are flexible resources, such as the community battery, are grouped together (bottom of Fig. 1).

2.0.1 The cost of energy and energy transport

In Australia, the cost of energy per kWh includes two components – the cost of energy and the cost of transporting the energy, typically referred to in Australia as transmission use of service (TUoS) or distribution use of service (DUoS), for the transmission/distribution networks respectively. For energy transport costs, we investigated two scenarios. The first scenario reflects business as usual, where DUoS was constant on the distribution grid. For the second scenario, which is not currently allowed according to the National Energy Rules, (NER), the cost of transporting energy locally was cheaper compared to transport on the wider distribution network (Local Use of Service or **LUoS**). As shown in Fig. 1, local energy exchange refers to energy exchange to and from the shared CES as well as between customers (i.e. peer-to-peer, P2P). A reduced price for local energy transport reflects the fact that transporting energy locally will incur lower costs for the network compared to transporting that same energy more widely.

For our models, DUoS is modelled as λ^{rt} (for remote energy transport) and LUoS as λ^{lt} (for local energy transport). λ^{rt} applies to 'remote' energy transfers E_{cl} and E_{cb} in Fig. 1. λ^{lt} applies to 'local' energy transfers i.e. E_{gl} and E_{gb} and E_{bl}. Energy costs λ^{e} is the same price everywhere (given by the NEM spot price) and energy transport costs only apply to imported energy, consistent with electricity rule 6.1.4.

Based on the energy flows in Fig. 1, the net cost to all connection points in our local energy system, including the CES, is:

$$
\begin{aligned}
C_{\text{LES all}} = \Sigma_{cp}(\lambda^{e}_{r+} + \lambda^{rt})(E_{cl} + E_{cb}) \\
-\lambda^{e}_{r-}(E_{gc} + E_{bc}) \\
+(\lambda^{e}_{l+} + \lambda^{lt})(E_{gl} + E_{gb} + E_{bl}).
\end{aligned} \tag{1}
$$

Note that the flow of energy from local generation to the CES and back to local demand is charged the transport fee twice, once for charging the CES (E_{gb}) and then for discharging the CES (E_{bl}). Therefore, if the local transport cost (λ^{lt}) was equal to the remote transport cost (λ^{rt}), this would be a major financial disincentive for the CES to be used for local energy transfer, and the CES would rather favour energy exchange with the wider network i.e. simple grid energy arbitrage (E_{cb} and E_{bc}). This is a major impediment to the viability of the use of local energy storage for customer demand management, and may be argued to be a perverse disincentive given that the CES is acting only to time shift the energy that customers have generated with their own rooftop solar systems for use later in the evening – a service that can potentially also improve network conditions.

3 Calculating battery costs

We assumed battery costs of AUD $1000/kWh, based on a report from AECOM [1] [4] . The battery **capital expenditure (CAPEX)** was defined as $battery\_capex = cost\_kwh*battery\_capacity$. If the battery is purchased outright, or with zero interest rate, we defined the annualised battery cost as the cost of the battery capex divided by the battery life (10 years, see Table 1 for full list of assumptions).

For a non-zero interest rate, the annualised battery cost was defined as:

$$annualised\_cost\_battery = CRF * battery\_capex \tag{2}$$

Where CRF is the capital recovery factor and defined as:

$$CRF = interest\_rate/(1 - (1 + interest\_rate)^{-battery\_life}) \tag{3}$$

Parameter	Value
battery type	Lithium
battery life	10 years
degradation	not considered
battery round-trip efficiency	90%
battery C-rate	0.5
η_{ch}, η_{dis}	95% , 100%
battery throughput cost	3.2c/kWh
transformer capacity	400kW

Table 1: Key assumptions

The battery **operation expenditure (OPEX)** was based on a figure of AUD$16/kWh p.a., estimated in a report carried out by AECOM [4] i.e. $battery\_opex = 16 * battery\_capacity$.

4 Calculating battery services and associated revenue

This analysis is based on four services that can be monetised including demand management for customers, two market services (energy arbitrage and FCAS support) as well as a network

[1] The AECOM report cited $\sim US\$1000 - 1800/kW$

service fee for increased network utilisation. Note that the battery can provide at least four further network services (backup power, network upgrade deferral, network congestion relief and network resource adequacy) but these services are not yet directly monetisable, so were not modelled for this report. It is worth noting that many of these non market based services were mentioned as critical values to householders and networks in our stakeholder research.

4.1 Calculating costs for customers

The community battery allows customers to store excess solar PV generation during the day, to be used later – a service typically referred to as 'demand management'. This can directly save the customer money if they can buy back their own solar energy at a cheaper price than grid-sourced energy.

For the purposes of our modelling, we pay customers the spot market price for their excess solar PV energy generation. In practice, the customer's choice of retailer would determine how much the customer is paid for this energy, typically in the form of a 'feed in tariff' (FiT). Each state typically sets a minimum FiT that customers must be paid. For each of the models outlined in this report, the battery owner could tailor the FiT payment to encourage buy-in and give a sense of community ownership to the battery.

It is important to note that, for most of the results presented here, we have used a reduced energy transport fee (LuOS, introduced in section 6.1). In this way customers also receive a discount on energy purchased *from* the battery. This contributes to the 'customer savings' shown in the results. Importantly, we have allowed *all* customers, with or without solar PV, to purchase energy from the community battery. If implemented in practice, this could provide a mechanism for customers to access renewable energy, for those who currently do not have access. Investigating whether customers have equal access to renewable energy – if they so choose – is an important aspect of our research.

For our analysis, we calculated the value customer demand management, C_{DM} based on the cost for energy paid by the customer $C_{customer}$ *without* the shared battery, minus the total cost for energy paid by the customer $C_{customer}$ *with* the shared battery. Cost for the consumer was calculated as:

$$C_{customer} = \Sigma_{cp}(\lambda^e_{r+} + \lambda^{rt})E_{cl} + (\lambda^e_{r+} + \lambda^{lt})E_{bl} \\ -\lambda^e_{l+} * (E_{gc} + E_{gb} + E_{gl}). \tag{4}$$

4.2 Calculating the value of battery energy arbitrage

The battery can buy and sell (arbitrage) energy both with the grid (E_{cb} and E_{bc}) as well as with customers (E_{gb} and E_{bl}). Therefore the total revenue from energy arbitrage C_{EA}, was calculated as:

$$C_{\text{EA}} = \ (\lambda^e_{r+} + \lambda^{rt}) * E_{cb} - \lambda^e * E_{bc} \\ +(\lambda^e_{l+} + \lambda^{lt}) * E_{gb} - \lambda^e_{l-} * E_{bl} \tag{5}$$

4.2.1 FCAS revenue

As outlined in Section 1, the battery can participate as both a generator and a load in the FCAS market. Here, we assume that the battery will only participate in the six contingency services, as battery operation for regulation FCAS requires significantly greater energy throughput.

Those contingency services are: generation across three time periods (RAISE6sec, RAISE60sec, RAISE5min) and load across three time periods (LOWER6sec, LOWER60sec, LOWER5min). Market prices vary across regions in the NEM. Here, we calculated potential FCAS revenue based on prices from the NEM site for NSW region for the whole of 2018. These are provided in 30 minute intervals which were resampled to 5 minute intervals.

The minimum generation/load quantity to offer on the market is currently 1MW. We assume that, if the battery is less than 1MW, it is participating in an aggregation scheme where collective assets can contribute above the minimum bid. For each time interval we calculated the power of the battery available for charging and discharging based on the total power of the battery (P_{total}) and the amount of power the battery was already discharging (P_{bl} + P_{bc}) or charging (P_{gb} + P_{cb}) for that time interval.

$$P_{discharge} = P_{total} - (P_{bl} + P_{bc}) \tag{6}$$

$$P_{charge} = P_{total} - (P_{gb} + P_{cb}) \tag{7}$$

Based on the prices for each of the six contingency FCAS services (RAISE6sec, RAISE60sec, RAISE5min, LOWER6sec, LOWER60sec, LOWER5min), we calculated FCAS revenue ($FCAS_{RAISE}$ and $FCAS_{LOWER}$) for each 5 minute timepoint as follows:

$$\begin{aligned} FCAS_{RAISE} &= \sum_t (RAISE6sec + RAISE60sec + RAISE5min) * P_{discharge} \\ FCAS_{LOWER} &= \sum_t (LOWER6sec + LOWER60sec + LOWER5min) * P_{charge} \end{aligned} \tag{8}$$

The total FCAS income was equal to $FCAS_{RAISE} + FCAS_{LOWER}$. Note that, we did not model any actual power delivery for FCAS contingencies, given that there are only on the order of 30 contingencies a year and each one lasts for a small fraction of an hour. We considered that the energy impact is essentially negligible.

4.3 Calculating the value of network services

CES can provide at least four network services including network demand management, network upgrade deferral, congestion relief and resource adequacy. For the calculations in this report we have estimated the value of network demand management only. For the remaining services (network upgrade deferral, congestion relief and resource adequacy), an agreement for the value of these services would need to be made with the local DNSP. The agreement would need to assure the DNSP that the service the battery has been contracted to provide will actually be provided when required by the system operator. The contract should include (a) rules covering penalties for non-delivery and (b) verification of the battery control algorithm: to guarantee the security of supply to the DNSP. This type of agreement could be developed under current regulations, although note that our accompanying social research suggested that exploring these types of options may require a 'culture change' among DNSPs to consider non traditional forms of network savings [3].

Network demand management can be used to maintain peak power flows on the distribution network within the limits of network hardware; a challenging task with increasing solar PV generation during the day resulting in peak power exports often exceeding the transformer rating limits. The typical solutions include curtailing solar PV, installing on-line-tap-changers (OLTCs) to regulate voltage excursions, or installing local storage. Further solutions based on advanced inverter functionalities are also being trialed. New types of substation CES units could provide voltage regulation though their four quadrant inverters without need to have OLTC in substation anymore.

Although inverter functionalities are showing promising results, their capacity is ultimately limited by the physics of the power flows within the local network.

We calculate the value of local storage to the DNSP in terms of 'increased network utilisation'. We assume that all energy over the power capacity rating of the distribution transformer (here we have assumed 200kW [2]), would be curtailed. Therefore we calculated how much energy, over 200kW, was displaced by the battery ($E_{displaced}$). The value of this displaced energy was priced based on the DUoS energy transport cost (λ_l^t) used in the energy cost calculations above (Section 2.0.1).

4.4 Applying the cost-benefit modeling to a case-study in the suburb of Jacka, ACT

Together with the Battery Storage and Grid Integration Program (ANU), the ACT Goverment Suburban Land Authory (SLA) is investigating the installation of a community battery in the new suburb of Jacka, as an alternative to the currently-planned subsidised residential battery scheme. We are working together with the local DNSP, Evoenergy. The cost and revenue calculations in this report are based on figures relevant to the Jacka case study.

Jacka is a planned new suburb in the ACT with construction scheduled to begin in 2021. Every residence will be mandated to host 5kW of solar PV. The ACT residential rooftop solar PV market is one of the fastest growing in Australia, and growing still with several new residential developments mandating 100% solar PV installations, with a minimum size of 3kW per dwelling required to be installed [5]. The effects of these developments on the Evoenergy network will see significant reverse power flows from the LV to the 11kV HV networks, affecting customer power quality. This level of solar PV penetration will require electricity network planning to manage expected large reverse power flows.

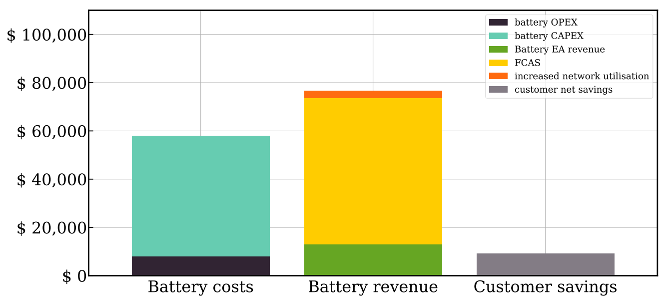
[2] This number is based on the actual capacity rating of 400kW for a distribution transformer in the Evoenergy network that would serve approximate 500 households. Here we have 200 households so we proportionately reduced the rating to 200kW.

The presence of residential rooftop solar PV connecting to the Evoenergy low voltage network has been shown to directly impact electricity networks via excessive voltage rise, thermal overload of low voltage feeders, harmonic excursion and load balancing challenges on distribution feeders. Evoenergy is aware that other Australian electricity utilities have implemented low voltage monitoring programs to gain intelligence of the effects of distributed generation connecting to networks. For example, Energex have implemented an extensive substation monitoring program by deploying power quality devices at the distribution transformer level, while the Victorian government mandated the roll-out of smart meters at the household and business level. These programs have substantially increased the capability of distributors to monitor voltage.

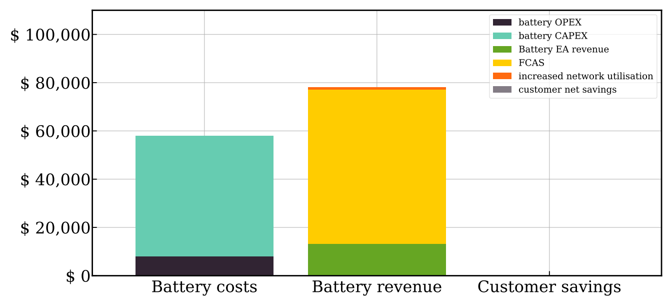
Evoenergy, as the local electricity network provider, has considered two solutions to managing voltage issues in new suburbs like Jacka. The first is to install on-line tap-changers (OLTCs) which provide a voltage step-down that would prevent overvoltage issues from the reverse power flows. The second is the community battery solution. The battery would 'soak up' excess energy generated in the middle of the day at maximum solar PV generation, shifting it for use later in the day, thus providing demand management for both customers and the network.

5 Cost/benefit results overview

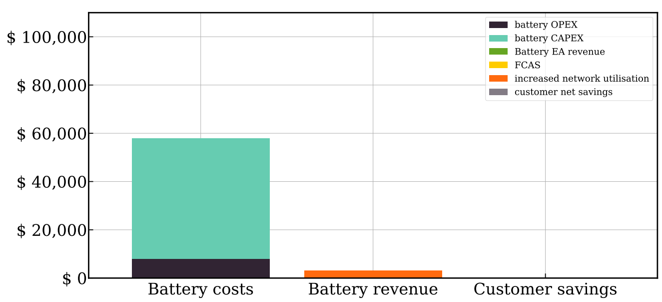
Here we provide an overview of cost/benefit results for the four models examined. Full details and results for each of the ownership models are given in section 6. Battery costs, battery revenue and customer savings for the four models is shown in Fig. 2, where 2a and 2b are owned by a third party e.g. a white-label retailer or a local council, and 2a and 2a are owned by a network. Briefly, 2a the battery is operated to maximise the profits for the battery owner as well as customers, but in 2b, the control strategy is to maximise the profit for the battery only. Both 2c and 2d are owned by a network, with the first operated without any knowledge of market prices, as the network is not allowed to buy and sell energy on the market, and for 2d the network leases 50% of the battery to a 3rd party (licensed retailer) who can operate that proportion of the battery as a for-profit model (optimisation is with respect to market prices).



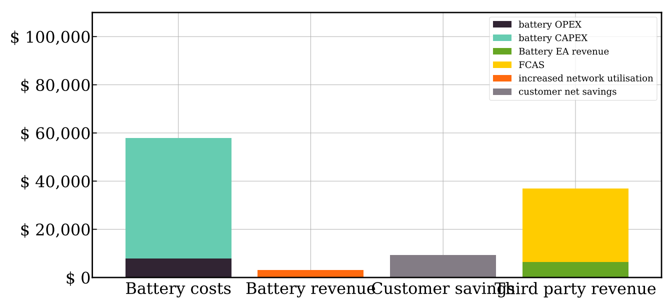
(a) Third party owned, community battery



(b) Third party owned, for-profit battery



(c) DNSP owned, community battery



(d) DNSP owned, for-profit battery (3rd party)

Figure 2: Costs and revenue for one year (2018) for the four models examined.

For each model, the battery cost is the same but battery revenue and customer savings differ. Importantly, although customers are much better off with the third-party owned community battery, the battery owner still makes almost as much money from energy arbitrage and FCAS. Also note that for the network owned, community battery - even while not optimising for market services – customer still save money. In practice, these savings could be shared between the customers and the network e.g. via a subscription fee. For the two network owned batteries, additional revenue would in practice be added to the stack due to avoided network upgrades, if the battery was placed in a constrained part of the network, where e.g. a transformer would otherwise be needed. We have not modelled those avoided network upgrade benefits as they are network and location dependent.

6 Cost/benefit results in detail

6.1 Third party owned, community battery

Under this model, the owner/operator could be e.g. a local council, a community group or a non-profit retailer. For the local council and community option, the "customer savings" could either be redistributed to the community or returned directly to customers as bill savings. The battery would be operated to provide the best outcome for customers, while ensuring the battery is financially viable and the network continues to receive income. To achieve this, the battery optimisation algorithm is operated to simultaneously maximise the profit for (i) customers, (ii) the battery and (iii) the network. See table 2 for prices. In this model, the battery operator receives a payment from the network operator, for increased use of the network (detailed in Section 4.3).

usage	maximise revenue all stakeholders
Energy import/export price ($\lambda^{e}_{r/l}$)	NEM spot price
DUoS (λ_{r_t})	\$0.05
LightYellow LUoS (λ_{l_t})	(i) \$0.05/kWh (ii) \$0.0/kWh
battery energy capacity	500 kWh
battery power	250 kW
Number of houses	200
Total solar generation	975 kW
Simulation duration	one year (2018)

Table 2: Parameters for a third party owned community battery

Initially, the energy transport price was set to the local DUoS price, which is business as usual. However, as shown in Fig. 3, we observe that, **without a discounted local transport cost, the battery is hardly utilised**, as the double charging for transport of energy (to charge as well as to discharge the battery), creates a strong financial disincentive to do so. For this reason, we use a discounted energy transport cost for all subsequent calculations. Note that while such a discounted energy transport cost is currently now allowed on the NEM, a rule change to alter this has been discussed by policy makers in recent years as a ‘local use of service’ (LUoS) charge that can replace DUoS charges to incentivise local energy trading. In the meantime, networks may flexibly allow a discounted DUoS under regulatory sandboxing arrangements.

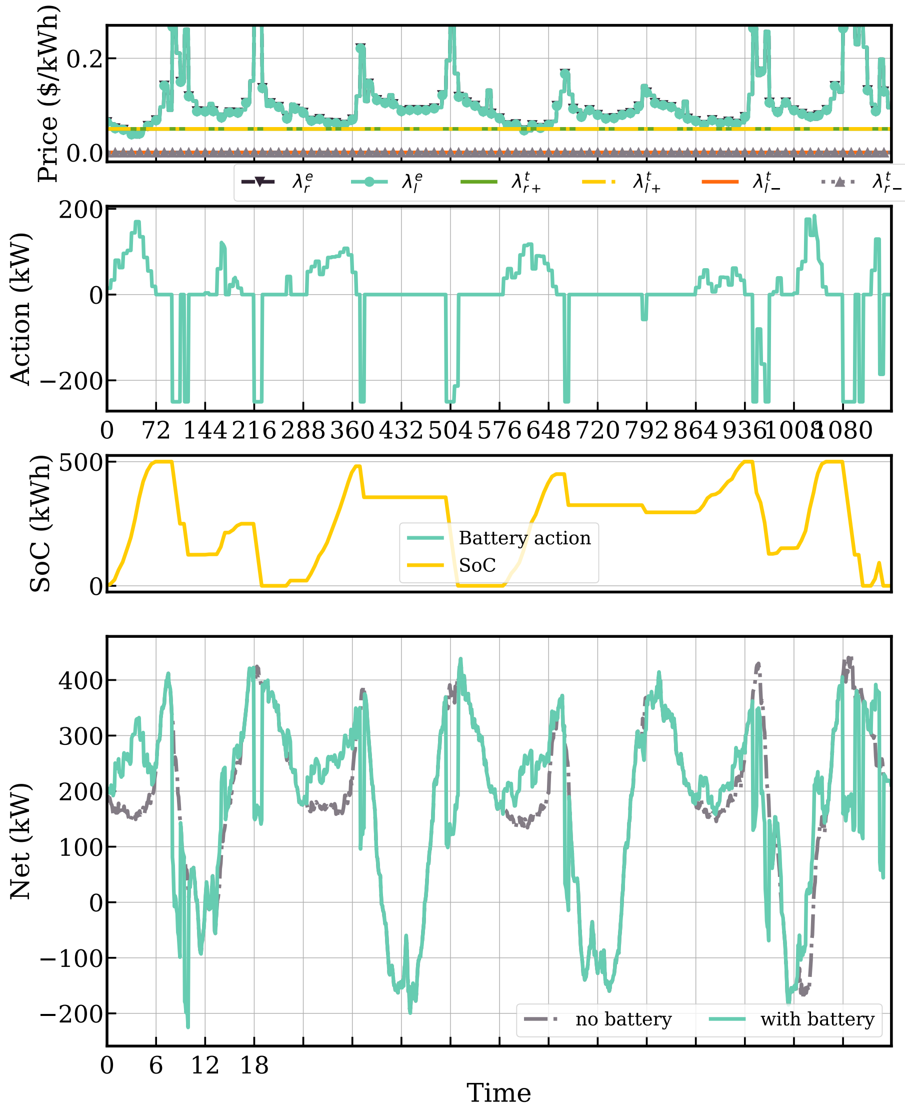


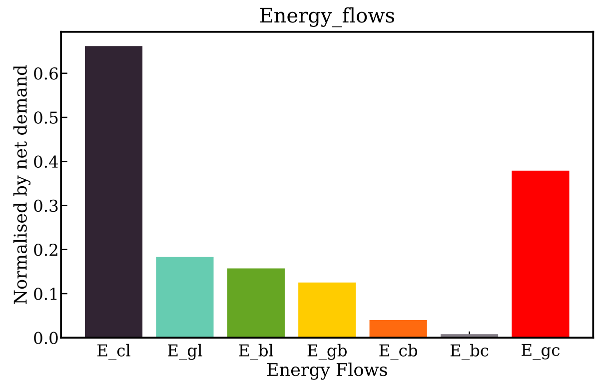
Figure 3: Third party owned community battery, **with DUoS**, for four days (18-21st June, 2018). Price (top panel), battery action (second panel), battery state-of-charge (third panel) and impact of battery on aggregate demand (bottom panel). Note that the battery is hardly being used (only for a few price spikes) and therefore makes almost no difference to aggregate demand. We can conclude that, **without a discounted local energy transport cost, using the battery is too expensive, as the energy transport cost is double-charged (once to charge and once to discharge the battery)**. Therefore, we use a discounted energy transport cost for all subsequent calculations.

6.1.1 Results for battery operated by third party, not-for-profit (LUoS)

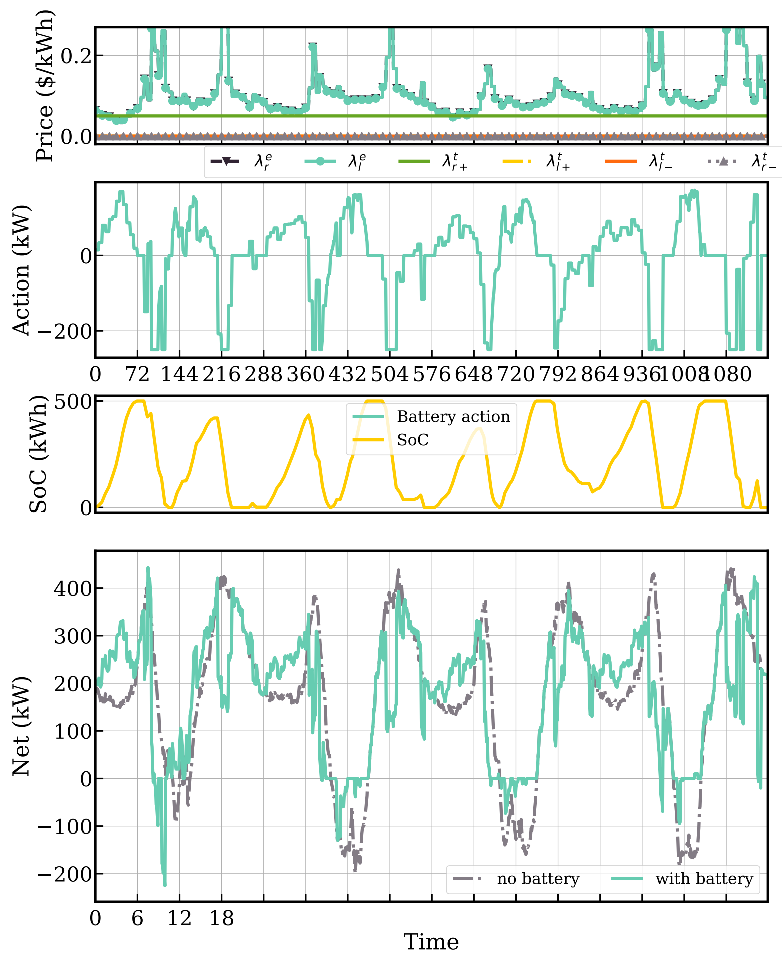
For this model, we introduce a reduced local energy transport price (LUOS, λ_{l_t} = \$0.0), which creates a financial incentive to use the battery for local energy trading, charging from excess residential solar generation, and discharging to meet local load requirements. As a result, we see significant reduction in total energy imports/exports ($\sim$16%), as detailed in table 3. Note that peak power demand and export is actually increased with the CES, due to sharp charging and discharging for energy arbitrage with the grid. Fig. 4 shows the battery operation and the impact on aggregate demand, as well as the energy flows associated with the battery. The energy flows show that the LUOS transport price incentivises the battery to charge from locally generated solar and discharge to meet local demand. As a result, import and export power peaks are reduced. Fig. 5 shows the costs versus revenue for this battery model, over the same time period.

Results for third party non-profit battery simulation (with LUOS transport cost).	
battery cycles per day	1.2
Average cost per house	\$428.66
Peak power demand, no battery	532.22.4 kW
Peak power demand, with battery	649.51 kW
LightYellow Peak power export, no battery	-814.5 kW
LightYellow Peak power export, with battery	-890.4 kW
Sum energy import, no battery	1061051.8 kWh
Sum energy import, with battery	915713.5 kWh
LightYellow Sum energy export, no battery	-975927.1 kWh
LightYellow Sum energy export, with battery	-830588.8 kWh

Table 3: Results for a third party community battery **with discounted local energy transport price**. Results are for 200 houses for one year (2018).

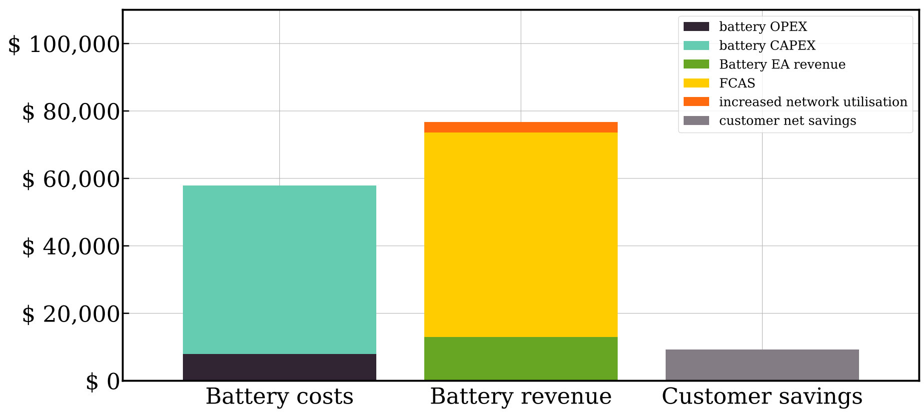


(a) Energy flows

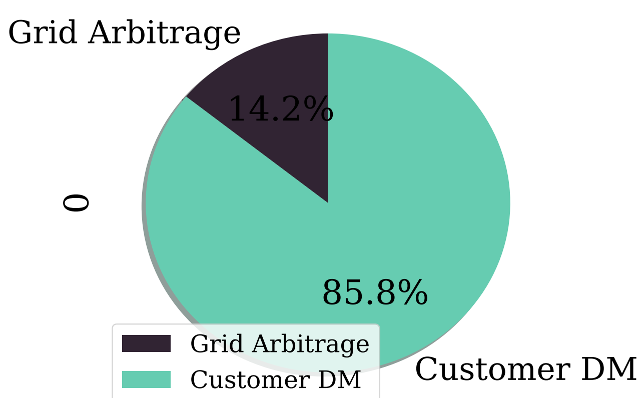


(b) Prices, battery action, state-of-charge (SoC) and net energy flows

Figure 4: Third-party, non-profit, **with LUoS**. Energy flows correspond to the sum over the whole year. Battery action and impact is shown for four days only (18-21st June, 2018). Note that, as shown in the energy flows (top figure), the LUOS transport price incentivises the battery to charge from locally generated solar and discharge to local demand, in addition to a small amount of energy arbitrage for price spikes. As a result, import and export power peaks are reduced (bottom panel).



(a) Cost/benefit plot for 3rd party owned, not-for-profit battery



(b) Energy arbitrage vs demand management

Figure 5: Third-party owned community battery **with LUoS**. (a) Cost/benefit plot and (b) balance of grid arbitrage vs Customer DR balance

6.2 Third party owned, for-profit battery

In this model, the owner/operator could be a retailer, an aggregator or another party operating the battery to maximise actual battery profit, rather than the customer profit. See table 4 for prices. Energy costs were given by the NEM spot market price for NSW. As for the non-profit model, we set λ^{rt} (DUoS) equal to 5c/kWh and λ^{lt} (LUOS) equal to 0c/kWh.

usage	maximise revenue for **battery only**
Energy import/export price ($\lambda^{e}_{r/l}$)	NEM spot price
DUoS λ_{r_t}	\$0.05
LUoS λ_{l_t}	\$0.0
battery energy capacity	500 kWh
battery power	250 kW
Number of houses	200
Total solar generation	975.3 kW
Simulation duration	one year (2018)

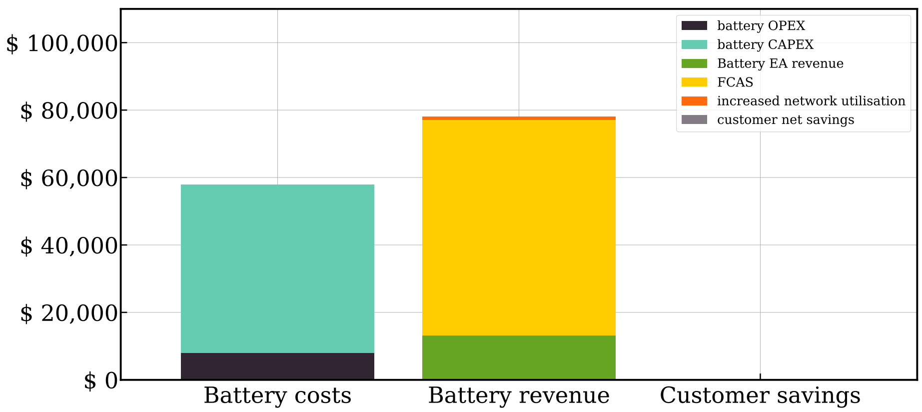
Table 4: Parameters for a battery operated by a third party for-profit operator e.g. an aggregator or a retailer.

6.2.1 Results for third party owned, for-profit battery

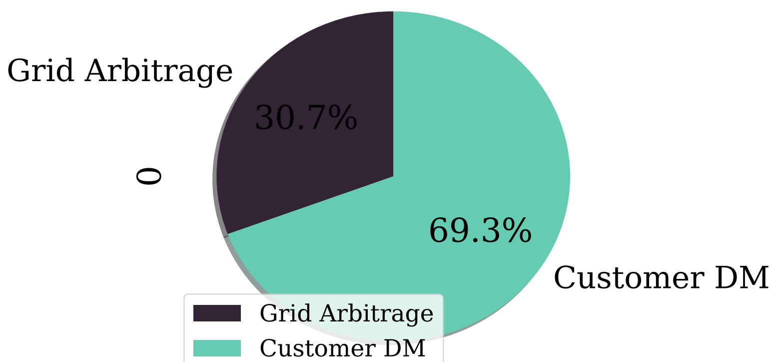
Here we see the battery is being underutilised, largely charging and discharging in response to price spikes, rather than from local solar generation, as shown more clearly over four days only (Fig. 7). Therefore the battery operation has only minor impact ($\sim 6\%$) on reducing net energy imports/exports (table 5). As with the third party owned community battery, peak demand/exports actually increase by ($\sim 11/18\%$), due to energy arbitrage behaviour. Fig. 6 shows the costs vs revenue for this battery model. As explained in Section 4.1, the model pays customers spot market price for their solar PV energy generation. However, for this model, the retailer could pay the customer a special feed in tariff (FiT) to encourage buy-in and give a sense of community ownership.

Results for third party profit battery simulation	
battery cycles per day	0.71
Peak power demand, no battery	532.2 kW
Peak power demand, with battery	631.1 kW
LightYellow Peak power export, no battery	-814.4 kW
LightYellow Peak power export, with battery	-906.7 kW
Sum energy import, no battery	1061051.7 kWh
Sum energy import, with battery	993052.4 kWh
LightYellow Sum energy export, no battery	-975927.1 kWh
LightYellow Sum energy export, with battery	-907927.8 kWh

Table 5: Results for 200 houses for one year (2018)

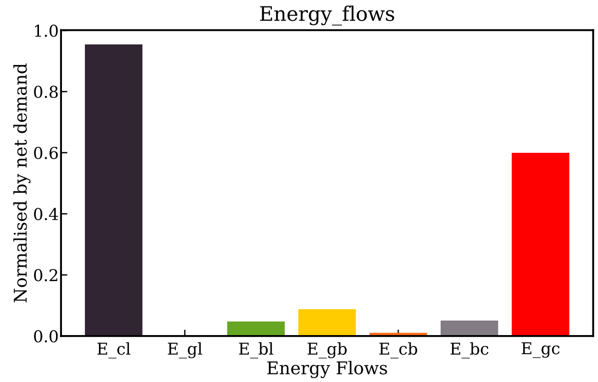


(a) Cost/benefit plot for 3rd party owned, for-profit battery

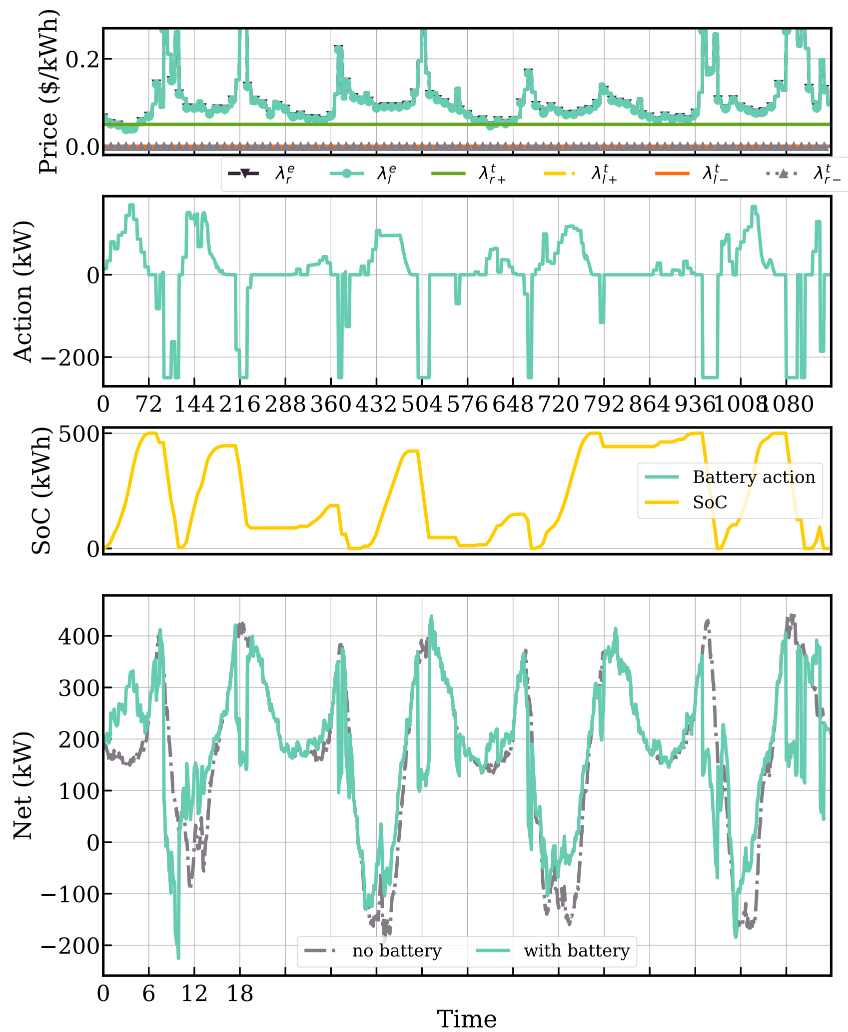


(b) Grid arbitrage vs Customer DR balance

Figure 6: Cost/benefit plots for 3rd party owned, for-profit battery.



(a) Energy flows



(b) Prices, battery action, state-of-charge (SoC) and net energy flows

Figure 7: Energy flows (a) and battery action summary (b). Battery action summary is for four days only (18-21st January). Energy and energy transport price (top panel), aggregate demand (with and without CES) (middle panel) and battery action with state-of-charge (SoC) (bottom panel).

6.3 DNSP owned community battery

Under this scenario, the battery is owned and operated by the network, both for network support, to increase hosting capacity, as well as to provide customer demand management. The network might consider this solution as an alternative to a grid upgrade, and/or to provide a service for customers for example, for whom reliability is particularly important. The battery was operated to minimise peak power export/import. Because the network isn't allowed to buy and sell energy to customers, we assumed a scenario where energy traded between customers and the battery was excluded from settlement on the NEM (to model this we set the local energy price and energy transport price to 0c/kWh), although this is clearly not allowed under current energy market rules. Customer savings could be split so that some of the savings go to the customer (solar PV owners who are charging the battery) and some of the savings are paid to the network, as a subscription fee for providing the virtual storage service. Other costs were given by Table 6.

usage	network services and customer virtual battery
Non-local energy price λ_r^e	NEM spot price
LightYellow Local energy price λ_l^e	0c/kWh
DUoS λ_r^t	\$0.05c/kWh
LUoS λ_l^t	0c/kWh

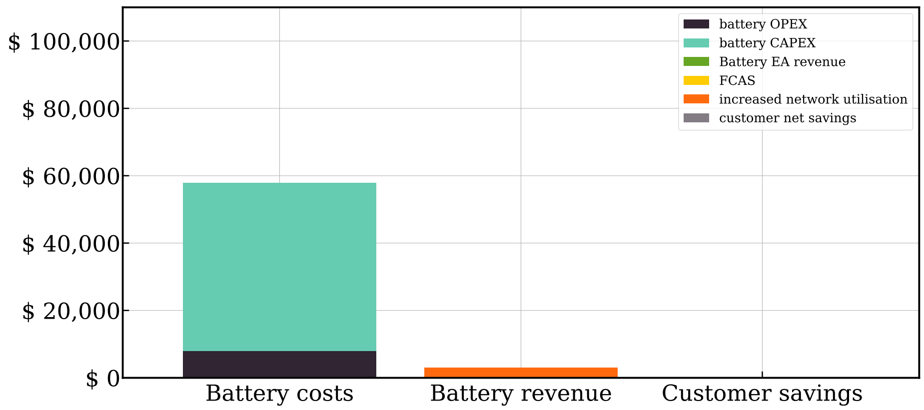
Table 6: DNSP-owned community battery prices. These are the prices used to calculate battery revenue and customer savings shown in Fig. 10. Note that, for the battery optimisation, we used the same prices as in table 2, in order to obtain correct battery behaviour.

6.3.1 Results for network owned, community battery

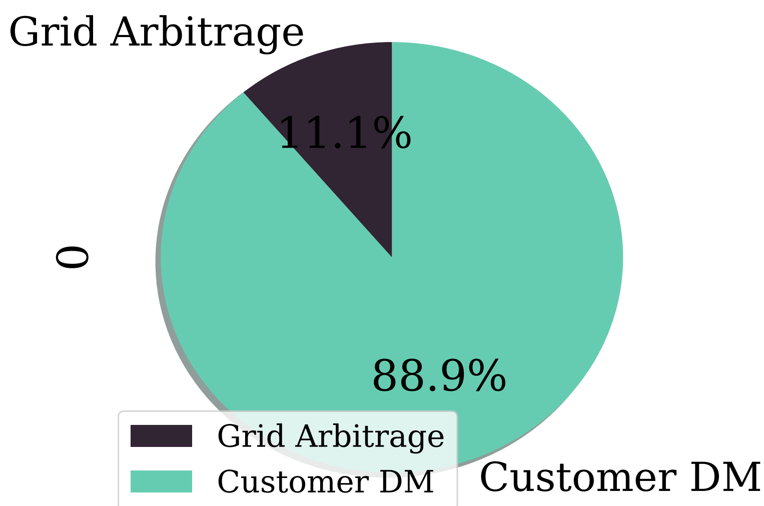
The battery works effectively to reduce peak and net energy imports and exports, as shown in table 7, with reductions on the order of $\sim$ 5% for power and 15-20% for energy. Therefore, the battery may provide a good alternative to a grid upgrade. At the same time, the battery effectively provided a virtual storage solution for customers, who were able to store their excess solar energy during the day, to be used at night.

Results for DNSP-owned, community battery	
battery cycles per day	1.21
Peak power demand, no battery	532.2
Peak power demand, with battery	503.0 kW
LightYellow Peak power export, no battery	-814.5 kW
LightYellow Peak power export, with battery	-798.0 kW
Sum energy import, no battery	1061051.8 kWh
Sum energy import, with battery	901052.3 kWh
LightYellow Sum energy export, no battery	-975927.1 kWh
LightYellow Sum energy export, with battery	-815927.6 kWh

Table 7: Results for 200 houses for the whole month of January, 2018

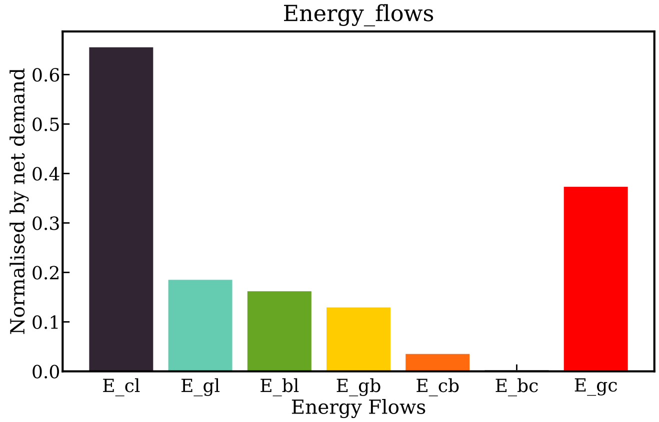


(a) Cost/benefit plot for network owned, community battery

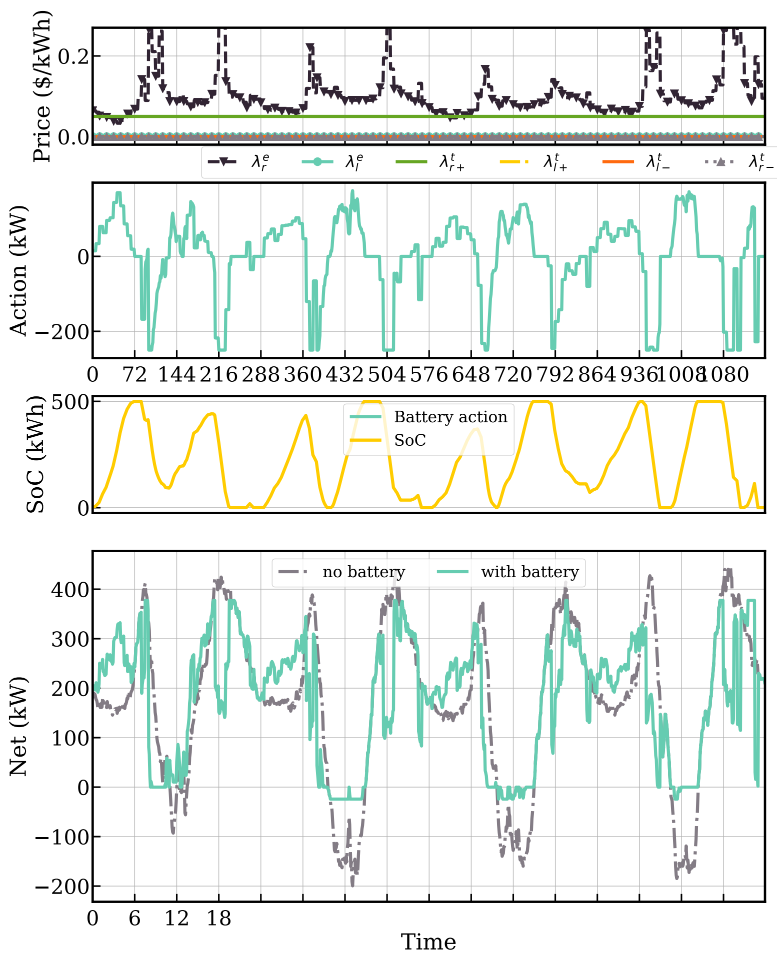


(b) Energy arbitrage vs demand management

Figure 8: (a) cost/benefit plot for DNSP owned community battery (500kWh) (b) and Grid arbitrage vs Customer DR balance



(a) Energy flows



(b) Prices, battery action, state-of-charge (SoC) and net energy flows

Figure 9: Energy flows (a) and battery action summary (b). Battery action profile for 4 days only (18-21st June, 2018) energy and energy transport price (top panel), aggregate demand (with and without CES) (middle panel) and battery action with state-of-charge (SoC) (bottom panel).

6.4 DNSP-owned, for-profit battery

Here the battery is owned by the network and part of the battery is leased out to a licensed retailer for energy trading. Therefore the battery is operated for both maximum network benefits as well as to maximise financial profits i.e. using multi-objective optimisation. We assumed that 50% of the battery would be leased, based on a bilateral contract between the DNSP and a licensed retailer for spot/FCAS/customer trading. Note that small generation aggregators (SGA) and market ancillary services providers (MASP) cannot fulfil this role under current regulations, because battery is a load in addition to a generator (**check this is correct**). We assumed that the retailer offers the battery as a service to customers and takes care of subscription and/or energy prices. Costs were given by Table 8.

Non-local energy price λ_r^e	NEM spot price
Local energy price λ_{l+}^e	NEM spot price
DUoS λ_{r_t}	\$0.05
LUoS λ_{l_t}	\$0.0
usage	50% network, 50% revenue (lease to 3rd party)

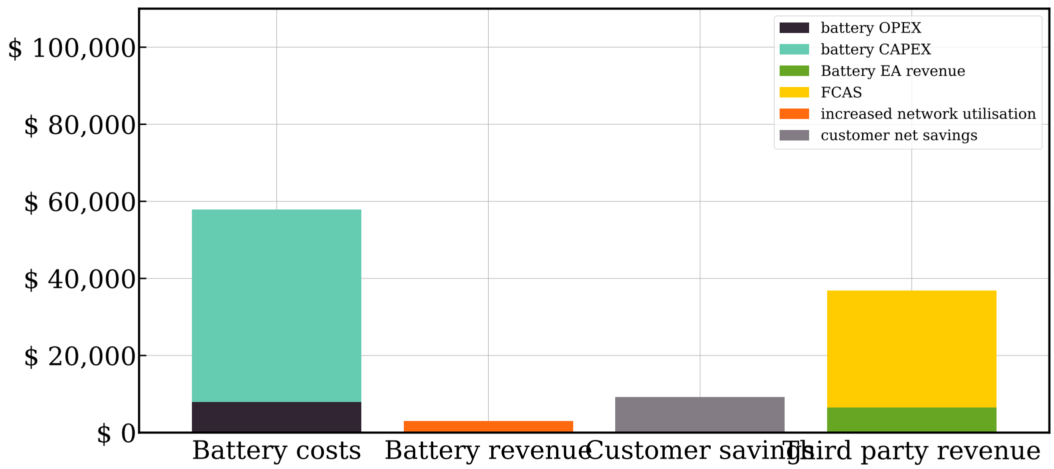
Table 8: DNSP owned, for-profit battery.

6.4.1 Results for network owned, for-profit battery

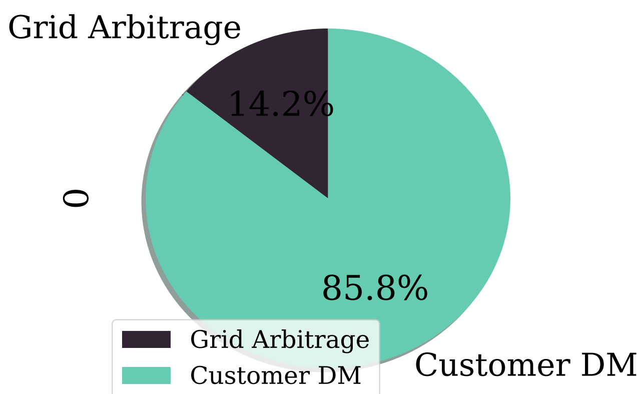
The battery works effectively to reduce peak and net energy imports and exports, as shown in table 9, with reductions on the order of 5% for power and 15-17% for energy. At the same time, the battery saved customers some money and generated almost $40,000 through energy arbitrage and FCAS. As with the trial in Alkimos beach in WA [2], customers could be charged a subscription fee for this service.

Results for DNSP owned, for-profit battery	
battery cycles per day	1.21
Peak power demand, no battery	532.2
Peak power demand, with battery	505.1 kW
LightYellow Peak power export, no battery	-814.5 kW
LightYellow Peak power export, with battery	-818.2 kW
Sum energy import, no battery	1061051.8 kWh
Sum energy import, with battery	915679.7 kWh
LightYellow Sum energy export, no battery	-975927.1 kWh
LightYellow Sum energy export, with battery	-830555.0 kWh

Table 9: Results network-owned, for-profit battery for 200 houses for one year (2018)

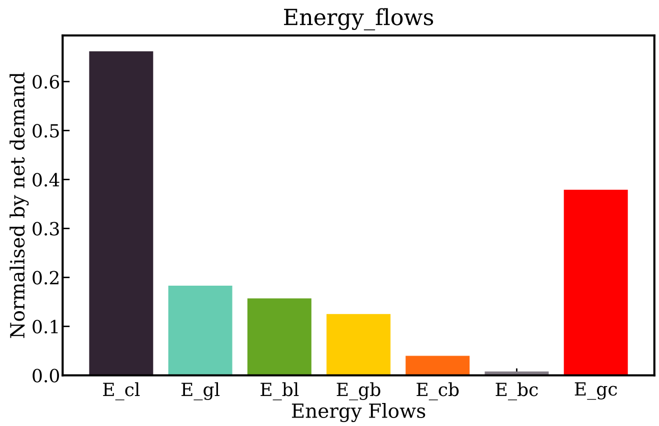


(a) Cost/benefit plot for network owned, for-profit battery

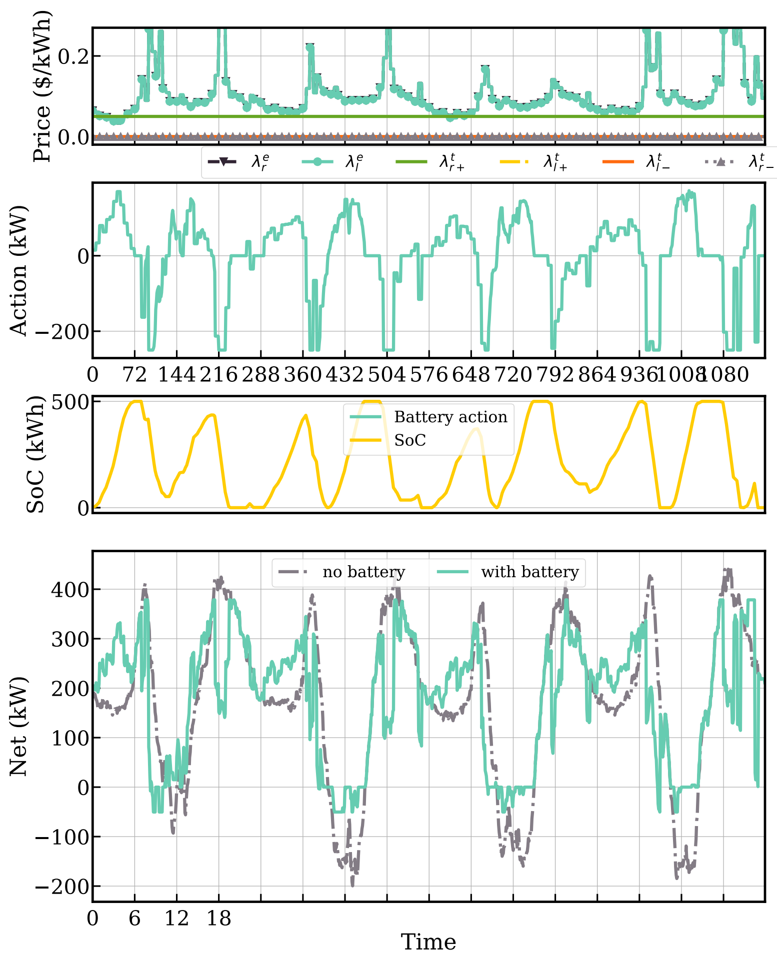


(b) Energy arbitrage vs demand management

Figure 10: Results for network-owned, for-profit battery (500kWh), (a) cost/benefit plot (b) and grid arbitrage vs customer DR balance



(a) Energy flows



(b) Prices, battery action, state-of-charge (SoC) and net energy flows

Figure 11: Energy flows (a) and battery action summary for four days (18-21st June, 2018) (b). Battery action profile for energy and energy transport price (top panel), aggregate demand (with and without CES) (middle panel) and battery action with state-of-charge (SoC) (bottom panel).

7 Limitations and Further Work

All of our modelling is based on perfect foresight, such that the estimated revenue is likely to represent a base-case-scenario. Future work will include market, demand and generation forecasts for more realistic revenue estimates.

In our models we did not calculate how much PV energy customers had exported to the CES, for the purposes of virtual net metering. We allowed all customers (PV owners or not) to purchase energy back from the CES (at a cheaper price if LUoS was used) until the CES was depleted. In this way, customers could potentially game the system and use a greater proportion of the cheaper energy than their neighbours. In practice, virtual net metering would need to be used for this reason.

It should be noted that a large component of our estimated revenue comes from the FCAS markets. Here we based our modelling on prices from 2018. However, it's currently unknown whether future FCAS market prices will increase or decrease, but given an increasing amount of storage coming onto the market, and limited FCAS requirements, prices may fall substantially. A recent report by AECOM, commissioned by ARENA, assumed that FCAS prices in each market would reduce exponentially to 10% of current values by 2040 [6].

8 Conclusions

Due to the wideranging potential benefits of community-scale energy storage (CES), there is an urgent need to understand whether storage of this scale can be effectively integrated into the National Energy Market (NEM) in Australia. There is enthusiasm for storage of this scale, from householders and energy sector professionals, as revealed by our own social research [3]. Furthermore, the potential benefits of community-scale storage may even increase over time as we increasingly electrify our energy system. Community batteries may offer an innovative, less expensive and more flexible solution to increasing demands on the distribution grid, in comparison to the alternative which is typically a grid upgrade.

This study has – for the first time – modelled both the financial flows and the energy flows for different models of community batteries. From this modelling, we estimated the multiple values a community battery can provide, for four different ownership models. There are clear implications in terms of distribution of financial revenue to different actors within the energy system. Some models may provide a way to increase access to renewables, for people currently locked out of the DER transition. These data are critical for policymakers who are weighing up the relative benefits of different models.

The ownership models we investigated were (1) third party owned community battery (2) third party owned for-profit model, (3) network owned, community battery, and (4) network owned, for-profit battery. For all models studied, a reduced local energy transport price (local use of service L̄UoS) was required to financially motivate local energy exchange (both with the shared battery as well as between customers i.e. peer-to-peer, P2P). In practice, this would be essential for the use of community batteries to 'soak up' locally generated solar and thereby increase local hosting capacity. LUoS is currently being discussed as a rule change to reflect the fact that transporting energy locally will incur lower costs for the network compared to transporting that same energy more widely.

For network-owned community batteries, a significant challenge is getting enough revenue, as networks are locked out of the energy and FCAS markets. Without these markers, such a battery is unlikely to be financially viable without adding a significant proportion of the battery cost to their Revenue Asset Base (RAB).

The network owned for-profit battery could potentially be financially viable under current market conditions, if a significant proportion of the battery was leased for market participation. This model is currently being trialled in practice for a grid-scale battery – the ESCRI-SA battery in Dalrymple, South Australia, owned by ElectraNet. Reports for that project suggest the battery is working successfully as a backup power source and for frequency stabilisation, in addition to generating significant income (AU$1M in 2018 [7]) from energy and FCAS markets for the third party operator, AGL.

Importantly, we found that third party owned community battery models are likely to be financially viable under current energy and FCAS market prices. They may also provide value to the widest range of stakeholders – customers, retailers, networks, battery owners – depending on how the benefits are distributed. However, to ensure the future economic viability of these models, payments for the network services they provide need to be established.

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