Centralised battery operation for community owned embedded networks

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The Australian electricity system is currently undergoing a critical transition from centralised, carbon intensive power generation to decentralised, renewable energy technologies in response to the growing threat of climate change. This shift introduces unprecedented opportunities for communities to improve energy empowerment and accelerate the transition to a clean energy future, through semi-off grid local energy schemes such as embedded networks (EN). ENs are private electricity networks which serve multiple customers and are connected to another distribution or transmission system through a parent connection point (PCP) (AEMC, 2019).

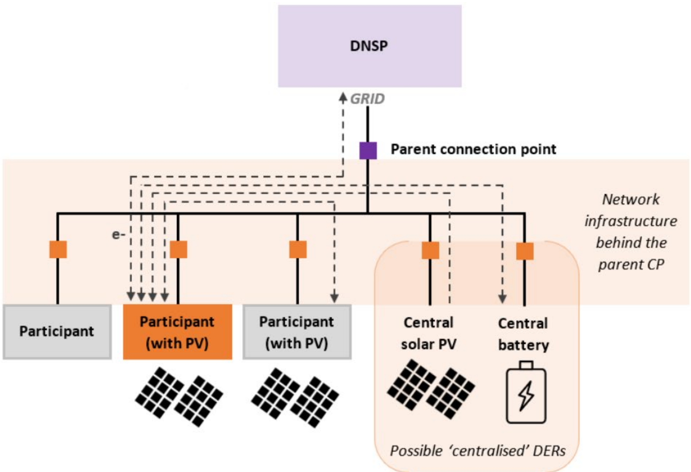

Figure 1 EN structure: Energy flows for a single participant (Stringer, et al., 2017).

Community ENs are defined as embedded networks which are owned by, and/or provide benefits for the community of households connected to them (Banks, et al., 2018). Given the often sustainability focused motivations and objectives of community energy projects, community ENs generally contain high levels of DER behind the parent meter (Bowyer, 2015). However, without energy storage, communities remain grid reliant and are subject to increasing power outages due to extreme weather events (Ausgrid, 2020). This study emerged out of an apparent gap in understanding of how a centralised battery energy storage system (BESS) can be operated within an EN to balance community objectives and ensure equitable outcomes. Specifically, the goal of this study is to demonstrate how a centralised BESS within a community EN can be operated to balance the potential environmental, resilience and financial benefits delivered to consumers.

This research was undertaken using Narara Ecovillage (NEV) as a case study, a community owned EN located on the Central Coast, operated and managed by energy utility NEV Power[1]. NEV Power's recently commissioned 437 kWh centralised BESS was modelled under five operation strategies, four retail tariffs and three financial sensitivity scenarios[2] yielding 57

[1] NEV Power was appointed to operate and manage the EN when the project commenced in 2016 and is a wholly owned subsidiary of Narara Ecovillage Cooperative.

[2] The financial scenarios intend to provide an economic framework for modelling and to indicate the sensitivity of outputs to financial inputs. A range of input parameters were adjusted and grouped into 'best case', 'realistic' and 'worst case'.

scenarios in total. The complete model comprises a fully customisable, interactive Microsoft Excel workbook which simulates results over a 20-year project life, with the intention for it to be used by other community ENs with similar objectives to NEV. In addition to the core model, the tool offers an interactive resilience model which determines BESS islanding performance for five unique outage scenarios under a range of customisable input conditions. As there is limited visibility of internal power flows within the EN, commercial and residential load profiles were built from available datasets to be used as inputs to the model. It is acknowledged that the resulting load profiles do not precisely replicate NEV's actual load profiles.

Scenario-based modelling method

The BESS operation scenarios emerged out of unique combinations of fundamental battery operation rules. A *load following* battery charges when there is excess PV generation and discharges when there is insufficient generation behind the parent meter to meet demand. *Peak targeting* restricts the load following behaviour to peak retail ToU and capacity charge windows faced at the parent meter to ensure there is enough reserve capacity in the battery to maximise self-consumption during peak periods. Further, *energy arbitrage* is performed by charging or discharging energy directly through the parent meter at a fixed rate during peak periods, surplus to the needs of the load (i.e. buying high and selling low). The BESS operation scenarios used in modelling are summarised in Table 1 below with reference to these rules of operation.

Table 1 Overview of scenarios for battery operation

Scenario	Designed to maximise?	Load following?	Target peaks?	Charge from grid?	Discharge to grid?
1. No operation	Network resilience	✗	✗	✗	✗
2. Load following	Self-consumption of PV	✓	✗	✗	✗
3. Peak targeting	Revenue	✓	✓	✗	✗
4. Cycle charging	Revenue	✓	✗	✓	✓
5. Discharge to grid	Revenue	✓	✗	✗	✓

The average annual daily battery state of charge (SOC) behaviour for each scenario is shown in Figure 2 below, indicating the depth of discharge (DoD) in each case. While there are many factors which affect battery life, generally, increased BESS utilisation (including more aggressive DoD) will lead to more accelerated capacity fade and ultimately earlier cell replacement[3]. Due to their conservative cycling parameters, scenarios 1 and 3 did not require capital battery replacement over the project life, while all other scenarios required replacement after 10 years.

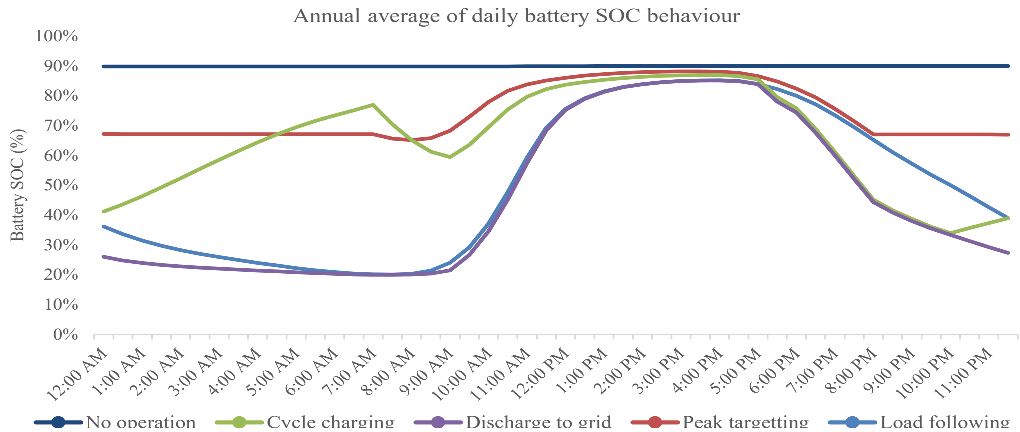

Figure 1 Battery scenario comparison of average daily SOC profile over year

[3] Battery SOH and cell replacement was incorporated into the financial model, but the environmental impact (embodied emissions) in the battery manufacturing was left unaccounted for.

Table 2 below provides a description of each of the four tariff structures, designed to reflect commonly used tariffs in industry as well as more innovative, cost-reflective models. Rates were chosen based on the average of plans offered by National Electricity Market (NEM) authorised 100% green energy retailers as of November 2021 (Energy Made Easy, 2021). In addition, the interactive excel model includes an embedded tariff comparison tool in accordance with requirements of the Power of Choice reforms designed to improve consumer protections within ENs (AEMC, 2012). Note that the customer behavioural response to cost-reflective tariffs is largely beyond the scope of this research, and that outcomes from testing tariffs are limited to mostly technical and economic outcomes.

Table 2 Overview of tariff scenarios

Scenario	Description
1. Flat rate	BAU existing tariff used onsite at NEV, single flat usage rate plus daily charge.
2. Solar ToU	Solar soak time-of-use (ToU) tariff designed to incentivise consumers to shift their load into periods of excess PV generation, and hence reduce flow across the PCP.
3. Demand charge	A demand charge was applied on top of a flat rate tariff to incentivise consumers to reduce their peak demand. The charge reflects the monthly peak energy usage during Ausgrid's capacity charge window to reflect charges incurred at the parent meter.
4. Battery use	A dynamic tariff designed to reflect the cost of energy delivered from the battery. If customers are importing energy while the battery is exporting, a percentage of battery use is allocated to them for that half hour period and the cost of that energy is assumed to be equal to the cost of energy from the battery[4].

Results synthesis and discussion

Table 3 below provides a synthesis of key results from modelling for the 'realistic' case financial scenario. The *environmental* results are shown as the percentage reduction in onsite[5] emissions compared to BAU over the project life. The *resilience* results are shown as the average percentage of time spent with power during a random one week network outage. The *financial* results depict the total net present value (NPV) over the 20 year project life assuming a discount rate of 4.39%.

Table 3 Summary of results: Average of economic sensitivity analysis scenarios

BESS scenario	Objective	Flat rate	Solar ToU	Demand charge	Battery use[6]
No operation	Environmental	0.00%	0.00%	0.00%	0.00%
	Resilience	82.16%	82.16%	82.16%	82.16%
	Financial	-$2,796,300	-$2,738,000	-$2,837,900	N/A
Load following	Environmental	35.89%	35.89%	35.89%	35.89%
	Resilience	76.02%	76.02%	76.02%	76.02%
	Financial	-$2,809,900	-$2,751,800	-$2,851,600	-$2,810,200
Peak targeting	Environmental	20.09%	20.09%	20.09%	20.09%
	Resilience	76.30%	76.30%	76.30%	76.30%
	Financial	-$2,742,900	-$2,685,500	-$2,785,300	-$2,839,500
Cycle charging	Environmental	10.49%	10.49%	10.49%	10.49%
	Resilience	75.63%	75.63%	75.63%	75.63%
	Financial	-$2,892,800	-$2,835,400	-$2,935,300	-$2,538,038
Discharge to grid	Environmental	25.28%	25.28%	25.28%	25.28%
	Resilience	75.95%	75.95%	75.95%	75.95%
	Financial	-$2,853,800	-$2,795,900	-$2,895,800	-$2,937,500

[4] This was determined as the sum of the battery wear cost and the cost of energy used to charge the battery, re-calculated annually according to formulas provided by HOMER (2021).

[5] The carbon emissions related to energy consumed onsite.

[6] The battery use tariff combined with the cycle charging scenario resulted in remarkably higher average bills for EN consumers (higher revenue for NEV Power) and was therefore deemed inequitable and neglected.

It was found that a 437 kWh centralised BESS within a community EN with oversized PV capacity can deliver up to 36% reduction in emissions arising from energy consumed onsite over a 20 year project life with operation strategies which target maximum load shifting. The BESS was able to improve village resilience during a network outage by 65 – 80% (depending on the battery SOH) but results approached 100% in all cases with the installation of a 50 kW generator, indicating that energy resilience may be better managed by hybrid solutions than by the BESS alone. The most favourable scenarios are the peak targeting and load following BESS strategies, both with the solar ToU tariff. The load following battery option provides a further 16% reduction in emissions from energy consumed onsite over the project life compared to the peak targeting battery, yet the latter offers additional savings of $66,300. Both scenarios are concluded as credible options, as this study does not provide any specific criteria for weighting community objectives. The results suggest that battery strategies which perform arbitrage are generally inappropriate for community ENs, as they were found to be highly sensitive to feed-in rates at the parent meter and must be oversized compared to internal load shifting requirements to also achieve community objectives.

The total overall battery costs outweighed the financial benefits delivered in all scenarios, amounting to deficit between $38,000 to $52,000 annually over the project life. The single largest expenditure over the project life was found to be internal labour expenses. Discounting these, economic analysis revealed that additional annualised revenue of approximately $30,500 p.a. is still required to break even over the project life. It is highly unlikely that small-scale community ENs can recover these outstanding costs through electricity sales alone, which would risk inequitable outcomes or dissatisfaction. This is consistent with findings from literature which assert a need for changes to regulation to allow community ENs to capture additional revenue streams to improve financially viability (Shaw, et al., 2019). Such revenue streams could include cap contracts, Power Purchase Agreements, spot price pass through at the PCP, or aggregation to form virtual power plants with access to Frequency Control Ancillary Services and other NEM markets.

Conclusion

The results demonstrate that a 437 kWh centralised battery can deliver up to 36% reduction in emissions and 80% improvements in resilience for NEV, yet the business case is unsubstantiated due to currently high capital and operating costs and overregulation of community ENs. In summary, *environmental* outcomes are maximised when load shifting is prioritised, *resilience* is optimised by minimal cycling, and *financial* outcomes were improved by strategies which target windows of peak charges faced at the point of grid connection. While financial outcomes were generally improved when modelled with a solar soak tariff, there is scope for further investigation into customer behavioural responses to cost-reflective tariffs and vehicle-to-grid opportunities which could be harnessed to optimise community objectives. Nonetheless, with additional funding support, falling battery costs and shifting regulation, there may be emerging opportunities for community ENs to recover their costs through market revenue streams to improve the value capture for a centralised BESS.

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