Demand Management Innovation Allowance Mechanism

Annual Compliance Report, 2019-2020

September 2020

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Contents

1 Introduction

This compliance report has been prepared as required for the application of the Demand Management Innovation Allowance Mechanism (DMIAM) by the Australian Energy Regulator (AER) for Ausgrid's 2019-2024 regulatory control period.

Ausgrid is required to submit an annual compliance report on expenditure under the DMIAM for each regulatory year by no later than 4 months after the end of the regulatory year (see section 2.3 of AER Guidelines for DMIAM – Electricity distribution network service providers, December 2017).

This Ausgrid annual DMIAM compliance report for the 2019-2020 regulatory year fulfils this requirement and is considered suitable for publication (with no confidential information included). As specified in Section 2.3 (3) of the DMIAM Guidelines, this annual DMIAM compliance report includes the following required information with section references bolded in brackets:

a) the amount of the allowance spent by the distributor; **[2.2]**
b) a list and description of each eligible project on which the allowance was spent; **[2.1]**
c) a summary of how and why each eligible project complies with the project criteria; **[2.1]**
d) for each eligible project on which the allowance was spent, and in a form that is capable of being published separately for each individual eligible project, a project specific report that identifies and describes **[3 to 10]**:
    i) the nature and scope of each demand management project or program,
    ii) the aims and expectations of each demand management project or program,
    iii) how and why the eligible project complies with the project criteria;
    iv) the distributor's implementation approach for the eligible project;
    v) the distributor's outcome measurement and evaluation approach for the eligible project;
    vi) the costs of the project or program:
        1. incurred by the distributor to date as at the end of that regulatory year;
        2. incurred by the distributor in that regulatory year; and
        3. expected to be incurred by the distributor in total over the duration of the eligible project.
    vii) for **ongoing** eligible projects:
        1. a summary of project activity to date;
        2. an update of any material changes to the project in that regulatory year; and
        3. reporting of collected results (where available).
    viii) for eligible projects **completed** in that regulatory year:
        1. reporting of the quantitative results of the project;
        2. an analysis of the results; and
        3. a description of how the results of the eligible project will inform future demand management projects, including any lessons learnt about what demand management projects or techniques (either generally or in specific circumstances) are unlikely to form technically or economically viable non-network options.
    ix) any other information required to enable an informed reader to understand, evaluate, and potentially reproduce the demand management approach of the eligible project.
e) Where an eligible project has extended across more than one regulatory year of the regulatory control period, details of the actual expenditure on each such project or program in each regulatory year of the regulatory control period to date. **[2.2]**
f) A statement declaration signed by an officer of the distributor delegated by the chief executive officer of the distributor certifying that the costs being claimed by each demand management project: **[2.3]**
    i) are not recoverable under any other jurisdictional incentive scheme,
    ii) are not recoverable under any other state or Australian Government scheme, and
    iii) are not otherwise included in forecast capital expenditure (capex) or operating expenditure (opex) approved in the AER's distribution determination for the regulatory control period under which the mechanism applies, or under any other incentive scheme in that distribution determination.

2 DMIA project and cost summary

This section of the report provides a summary of the Ausgrid projects and project costs over the 2019-2020 regulatory year for which DMIAM expenditure was incurred.

2.1 Project list, description and project criteria summary

The below table provides a list, description and summarises how and why each eligible project complies with the DMIAM project criteria (as required in Section 2.3 (3) (b) and (c) of the AER DMIAM Guidelines):

Project	Description	How and Why Project meets DMIAM Criteria
Stand Alone Power Systems	This project was developed to improve the techniques and processes by which Stand Alone Power Systems (SAPS) can be assessed as non-network options for Ausgrid's demand management investigations and regulatory investment test- distribution (RIT-D) projects.	This project will build demand management capability and capacity to consider SAPS as a potential alternative solution to an identified network need. This is expected to result in more efficient solutions in locations where the cost to serve customers is high due to their remote location.
Peak Time Rebate	Ausgrid is seeking to assess the cost-effectiveness of a peak time rebate (PTR) as a demand management solution in localised areas of the Ausgrid network area. This form of behavioural demand response will explore whether a rebate offer with customers on peak demand days can be used to alleviate location specific short-term network constraints, to defer or reduce the need for longer term network infrastructure upgrades.	This project was designed to research, develop and implement DM capability and capacity in the form of peak time rebates as a non-network alternative. It is considered innovative in that the proposed PTR trials will utilise technologies, techniques and processes that differ from those previously used in the market. Specifically, the project will leverage the roll out of smart meters and collaboration with electricity retailers.
Electric Vehicle Demand Research	This project will explore the future impacts of electric vehicle (EV) charging on the Ausgrid network and the viability and customer response to various demand management interventions. The project aims to first understand the possible electricity demand impacts from electric vehicle charging on network assets and then conduct or participate in EV trials that investigate the potential demand management options for addressing future network investment needs.	This project aims to build capability and capacity in managing the electricity demand from electric vehicle charging which is forecast to be a significant electrical load in the future. This research project is considered innovative in that it is Ausgrid's first in-depth research study into the emerging electric vehicle market in NSW and on Ausgrid's network. The modelling and research techniques utilised in the first phase of the project in conjunction with project partners also involve innovative modelling and analysis techniques.
Digital Energy Futures	This project is a 3-year research project being led by Monash University in which Ausgrid is a co-funding and	This project aims to build demand management capability and capacity in the household customer segment by better

	in-kind contributor in partnership with Energy Consumers Australia and Ausnet Services. The project aims to understand and forecast changing digital lifestyle trends and their impact on future household electricity demand, including at peak times.	understanding households existing and future trends in everyday household energy use practices and how effective demand management solutions can be developed for the household segment. This research program adopts innovative approaches by applying ethnographic research techniques and sociological theories to investigate how changing social practices will impact on electricity sector planning.
Cost Reflective Network Pricing Research	The nature and scope of this project is to quantify the peak demand reduction benefits from the introduction of cost reflective network pricing to residential customers to better understand the effectiveness of these pricing structures as a targeted demand management tool for network investments. The project also aims to understand what complementary measures can be used to increase the effectiveness of these network pricing signals.	This project is targeted at researching and developing demand management capability by better understanding how effective cost reflective network pricing is as a demand management option to reduce long term network costs. The project is considered innovative as it employs analytical and customer surveying techniques not previously implemented to research this topic. In addition, the segment of customers being studied is considered significantly different to other jurisdictions because of the significant length of time that residential customer's in Ausgrid's network area have been exposed to time of use network and retail pricing (10 to 15 years).
Community Battery Feasibility Study & Research	This project aims to investigate the potential for locally based community batteries paired with an innovative business model to offer both a competitive alternative to traditional local network investment and introduce a novel way to markedly improve equitable access to energy storage for customers. The project will involve a feasibility study on the engineering, regulatory and commercial aspects of the community battery concept and to also explore initial customer response, awareness and interest in the concept.	This project aims to build capacity and capability in demand management options specifically focusing on the potential for local community batteries to be used to cost-effectively address network investments driven by maximum or minimum demand network constraints or other drivers such as voltage management or system reliability or security. The project is considered innovative in that this concept is relatively new and has not been trialled by Ausgrid and within the National Electricity Market which makes the regulatory and commercial aspects of the concept challenging.
Demand Management for Replacement Needs (Power2U)	This project aims to test the viability of using non-network options to defer or manage the load at risk associated with network investments that involve retiring / replacing aged assets. Primarily, the project aims to test the effectiveness of customer incentives in a targeted geographic area that lead to new installations of technologies that offer permanent demand reductions (e.g. solar power and energy efficiency). This trial tests if targeted incentives can create additional customer activity (i.e. above business as usual).	This project aims to build demand management capability and capacity by exploring solutions targeted at non-network options that defer or manage the load at risk associated with network investments that involve retiring / replacing aged assets. Using non-network solutions to manage risk from replacement driven investments differs markedly from typical overload risk and requires an innovative approach to build a portfolio of permanent and temporary load reductions across the daily profile. This project is considered innovative in that applying demand management solutions to address aged asset related network

		investments is a new and emerging application of demand management.
Battery Demand Response (VPP) Trial	This project aims to investigate the potential application of demand response for residential batteries for network support services by engaging with customers with an existing battery system. It also explores whether battery VPPs can provide reliable and cost competitive sources of demand reductions, load management or voltage support services to defer network investment.	This research project explores the demand management capability of a battery VPP (Virtual Power Plant) with market providers. Battery VPPs are considered a new and emerging concept and the technology is rapidly evolving. The project is considered innovative in that this is a large scale VPP (multiple MWs of dispatchable capacity) being tested by a distribution network service provider across a range of different battery aggregators, aggregator and customer models and battery manufacturers.

2.2 Project cost summary

Actual project costs incurred are collected from project codes in Ausgrid's SAP reporting system. The amounts claimed are those booked to each project in the regulatory year. Costs include research and development of projects, implementation costs, project management and other related project costs from Ausgrid staff labour time or procurement of good or services from external parties. All costs are net of any project partner contributions.

Ausgrid incurred costs in the 2019-2020 regulatory year on a total of seven ongoing projects and one completed project with a total of $1,345,933 claimable costs under the DMIAM.The below table provides a project cost summary outlining the amount of the allowance spent during the 2019-2020 regulatory year and other regulatory years during the regulatory control period 2019-2024 for ongoing projects (Section 2.3 (3) (a) and (e) of the AER DMIAM Guidelines):

Project	Project status at end of June 2020	Incurred project costs 2019-2020 (excl GST)
Stand Alone Power Systems	Completed	$23,291
Peak Time Rebate	Ongoing	$40,786
Electric Vehicle Demand Research	Ongoing	$202,134
Digital Energy Futures	Ongoing	$174,565
Cost Reflective Network Pricing Research	Ongoing	$38,029
Community Battery Feasibility Study and Research	Ongoing	$267,578
Power2U (Demand management for replacement needs)	Ongoing	$311,450
Battery Demand Response (VPP) Trial	Ongoing	$290,314
TOTAL projects		**$1,348,147**

2.3 Statement on costs

In submitting this compliance report, Ausgrid confirms that the costs being claimed by each demand management project:

i) are not recoverable under any other jurisdictional incentive scheme,
ii) are not recoverable under any other state or Australian Government scheme, and
iii) are not otherwise included in forecast capital expenditure (capex) or operating expenditure (opex) approved in the AER's distribution determination for the regulatory control period under which the mechanism applies, or under any other incentive scheme in that distribution determination.

3 Stand Alone Power Systems

This project is a continuing Demand Management Innovation Allowance (DMIA) project from Ausgrid's last regulatory control period 2014-2019 into the current 2019-2024 regulatory control period. The following project report provides details of the project activities up until the end of the 2019-2020 regulatory year.

The project was completed during the 2019-2020 regulatory year.

3.1 Project nature and scope

This project was developed to improve the techniques and processes by which Stand Alone Power Systems (SAPS) can be assessed as non-network options for Ausgrid's demand management investigations and regulatory investment test- distribution (RIT-D) projects. To date, Ausgrid has dealt with only a few instances where SAPS have been investigated and implemented as a non-network solution.

3.2 Project aims and expectations

The primary objective of this project was to develop planning tools to effectively and efficiently evaluate SAPS solutions when assessing viable options to a network need.

Secondary objectives included identifying case studies in the Ausgrid network where SAPS are a potentially viable alternative to traditional network options and the associated customer engagement processes that might be needed to implement an individual power SAPS system or micro-grid SAPS solution.

3.3 How and why project complies with the project criteria

This project developed a set of planning tools based on a robust cost benefit assessment methodology to identify locations where SAPS offer an efficient alternative to traditional grid supply. This project will build demand management capability and capacity to consider SAPS as a potential alternative solution to an identified network need.

This is expected to result in more efficient solutions in locations where the cost to serve customers is high due to their remote location.

3.4 Implementation approach

The project was planned to take place over two years in 2018-2019 and 2019-2020 as follows:

Phase 1 - Costs Benefit Assessment tool development for SAPS

Development of a suite of tools that could be used to quantitatively assess whether a Stand-Alone Power System is a more cost-effective alternative to a traditional network solution. Two specific tools that were envisaged to be in scope of this phase of the project were:

Phase 1A - Stand Alone Power Systems planning tool

Development of planning tools to estimate the cost of implementing a SAPS for a defined set of customer and network characteristics. This phase of the project included:

- A whole-of-life SAPS sizing and costing tool that determined the optimum SAPS configuration based on customer interval demand data and a given set of constraints; and
- A customer interval demand data estimation tool where metered interval data is not available.

Phase 1B - Overall Cost Benefit Assessment tool

Development of a cost-benefit assessment (CBA) tool which captures all relevant costs and benefits associated with deploying a SAPS, including:

- Avoided costs associated with bushfire risk due to network assets traversing bushfire-prone areas;
- Avoided costs associated with safety risks due to electrical infrastructure;

- Avoided network asset replacement and maintenance costs;
- Financial impacts of improved customer reliability;
- SAPS installation costs; and
- SAPS maintenance costs.

The CBA tool delivered in Phase 1B would allow a consistent, quantitative assessment of whether SAPS deployment offers a cost-effective alternative to traditional supply-side network investment for a given part of Ausgrid's network.

Phase 2 – Case study identification and customer engagement

Phase 2 activities that were planned under the original scope of the DMIA project included trial site identification and customer engagement activities. The identification of trial sites is now being funded and delivered as part of Ausgrid's Network Innovation program. Customer engagement activities will also form part of the Network Innovation program.

Phase 3 – Stand Alone Power Systems pilots

Building upon work in Phase 1 and 2, one or more of the case studies identified in Phase 2 will be progressed to a pilot program. This work will also be delivered as part of Ausgrid's Network Innovation program. A potential future DMIA project exploring customer-based elements to an efficient SAPS solution will be considered in the development and delivery of the SAPS Network Innovation project.

3.5 Outcome measurement and evaluation approach

The use of the developed planning tools to assess where SAPS might offer a viable cost-effective alternative to traditional network investment, and to optimise the SAPS network innovation program are key measures of success for the trial. Results from the SAPS pilot program would also be used to evaluate and improve the SAPS planning model.

3.6 Costs of the project

The table below shows Ausgrid's actual project costs for 2019-2020, total project expenditure to date and the total **completed project costs**.

Table 1 - Project costs

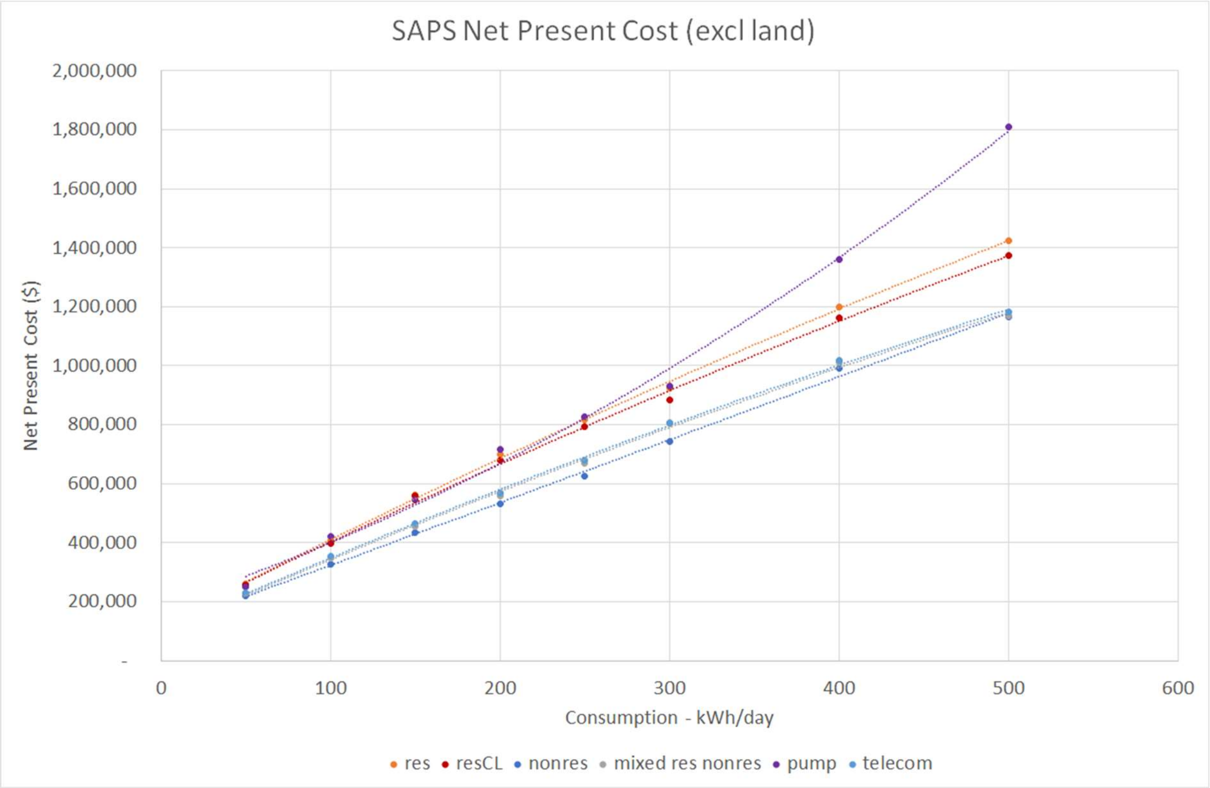
Budget Item	Actual project costs 2019-2020	Total project costs as at end of June 2020	Total completed project costs
Total project costs (excl GST)	$23,291	$75,184	$75,184

3.7 Project Activity and Results

3.7.1 Quantitative results of the project

The SAPS sizing and costing tool, which includes the commercial SAPS sizing software and the customer interval load estimation tool, was used to evaluate six use cases representing typical customer profiles across a spectrum of load sizes to determine the most feasible SAPS configuration and associated cost for each case. It was found that across most customer types, the lifetime cost of SAPS in present value dollars terms was approximately linear, except for irrigation pumping loads as shown in Figure 1 below. This was used for the SAPS cost component of the cost-benefit assessment.

Figure 1 - SAPS lifetime cost vs load size for various load types



For the SAPS benefit component, these were drawn from various inputs/models. These models included:

- Ausgrid internal high-voltage overhead risk models;
- Historical maintenance expenditure across the Ausgrid network; and
- Historical outage information across the Ausgrid network.

In a “do-nothing” scenario, these represent operational risks that escalate over time due to asset aging and environmental factors.

All cost and benefit inputs were consolidated and spatially allocated to the distribution substation level. A core assumption of the model is that a SAPS is assumed to replace a distribution substation 1-for-1. In this way, existing low-voltage networks are retained which avoids complicating factors such as voltage drop considerations as the modelled SAPS mimics existing grid supply.

The SAPS screening model has been developed using a high degree of automation. It is not a final decision-making tool, rather, it carries out an initial screening. There is still the need to carry out site-specific investigations such as terrain suitability, availability of land and customer/community engagement before candidate sites can be confirmed for SAPS.

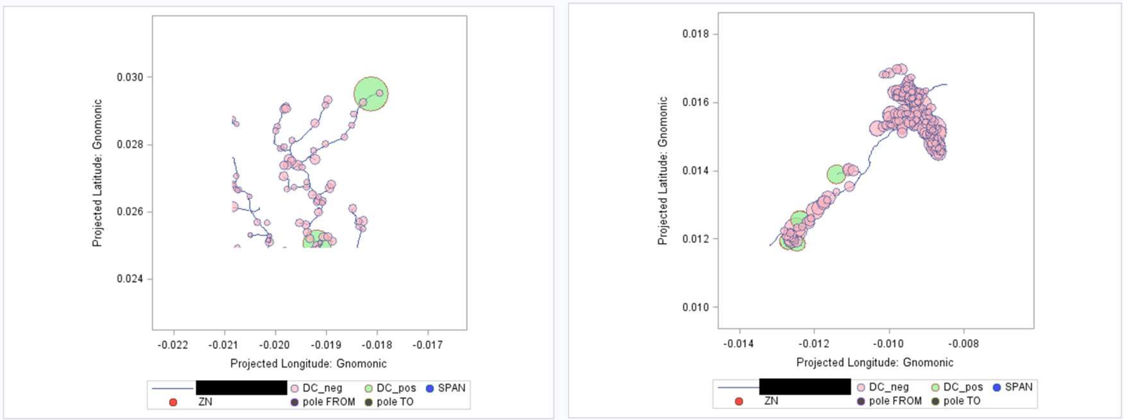
3.7.2 Analysis of the results

A total of 18 11kV feeders supplying over 3,000 distribution substations and 12,600 customers have been assessed for SAPS. Of the distribution centres assessed, around 90% serve 5 customers or less.

Based on the current set of inputs and assumptions, initial results indicate that for about 140 distribution substations, further investigation for SAPS viability is warranted. These will require location-specific confirmation of other factors before SAPS can be confirmed as viable.

SAPS suitability screening results of two feeder areas are shown below in Figure 2. The circles represent distribution substations considered for SAPS, with colour-coding denoting economic feasibility (yes/no) and bubble size representing the gross benefits per location.

Figure 2 - Screening results of two areas for SAPS suitability



3.7.3 How results will inform future demand management projects

A key benefit of the project will be the ability to more efficiently and effectively assess a SAPS alternative for many locations. We expect that once model inputs have been verified by the SAPS pilots; these tools will form part of our business as usual suite of planning tools for assessing competing alternatives to network constraints.

In this way, we are laying a foundation to improve the way we plan the network by quantitatively determining the costs and benefits of SAPS as an alternative to traditional network solutions that is consistent with the way other asset classes are planned. The high degree of automation will mean any changes to inputs and/or key assumptions can be quickly processed.

We envisage that this will improve the way we serve our customers in remote areas by improving their reliability of electricity supply. This will also contribute towards putting downward pressure on customer electricity bills by reducing the cost to serve customers in remote areas.

A potential future DMIA project exploring customer-based elements to an efficient SAPS solution will be considered in the development and delivery of the SAPS Network Innovation project.

3.8 Other Information

No other information is currently supplied or provided for this project. If you have a specific information request regarding this project which may assist you in understanding, evaluating or reproducing this project please contact demandmanagement@ausgrid.com.au.

4 Peak Time Rebate

This eligible project is a continuation Demand Management Innovation Allowance (DMIA) project from Ausgrid's last regulatory control period 2014-2019 into the current 2019-2024 regulatory control period. The following project report provides details of the project activities up until the end of the 2019-2020 regulatory year.

The project will be an ongoing project into the 2020-2021 regulatory year.

4.1 Project nature and scope

Ausgrid is seeking to assess the effectiveness of a peak time rebate (PTR) offer in localised areas of the Ausgrid network area on peak demand days. The project aims to test whether this option can be used to alleviate location specific short-term network constraints, to defer or reduce the need for longer term network infrastructure upgrades. The project will involve partnerships with energy retailers and other proponents and will be split into two phases as detailed in section 4.4 below

4.2 Project aims and expectations

The primary purpose of this project is to determine the viability of PTR as a demand management solution through building retail partnerships and conducting customer trials. As such the objectives are to gain an understanding of the:

- Scale and density of peak demand reduction offered by PTR under various modelled scenarios for constrained network assets;
- Various customer acquisition strategies and the resulting measure of localised PTR customer take-up;
- Effectiveness of various customer incentives;
- Customer experience;
- Reliability and availability of retailer PTR platforms; and
- DNSP costs associated with PTR events and payments to PTR providers.

4.3 How and why project complies with the project criteria

This project was designed to research, develop and implement DM capability and capacity in the form of peak time rebates as a non-network alternative. It is considered innovative in that the proposed PTR trials will utilise technologies, techniques and processes that differ from those previously used in the market.

Collaboration with retailers across targeted geographic areas as nominated by Ausgrid is an expansion on past retailer trials and will explore PTR customer density and provide insight into network support impacts.

If viable, the approach being trialled in this project has the potential to offer a cost-efficient alternative to network infrastructure upgrades in residential parts of the network. Collaboration on PTR trials is not eligible for recovery under the classifications specified under any other jurisdictional incentive scheme, state/Australian government scheme or included in forecast capital or opex approved in Ausgrid's distribution determination.

4.4 Implementation approach

The PTR project will take place across 2 phases, with the first phase commencing in 2020-2021.

The first phase of this project will include the implementation of collaborative PTR trials with retailers. These initial trials will take place in 2020-2021 and will confirm the functionality of the retailer PTR platforms, provide insight into targeted Retailer customer recruitment strategy and customer demand response and satisfaction.

As in any collaborative venture, information sharing will be a key enabler for the success of the trial. Consequently, Ausgrid will collaborate with our partners to better understand customer views and preferences.

Phase 1 of the trial will include suburbs in the Lower Hunter and Newcastle West areas of Ausgrid's service area. These areas have been selected as they are representative of the residential areas where network needs are forecast to occur in the near to mid-term.

The process and timing for demand response events will need to be negotiated with our market partners, but ideally will be customisable to address local network requirements in both Summer and Winter and have enough flexibility to reflect network operating arrangements. Identification of processes and contractual arrangements which maximise benefits to networks, Retailers and customers will be a key focus of collaborative efforts.

Phase 2 of the DMIA project will focus on exploring how we can increase the density of customer adoption for this solution in the trial areas to better understand the viability of this solution for network support purposes. Phase 1 partnerships may be continued and/or expanded or alternatively partnerships with other proponents may be established. The later stages of the trial may explore options such as the recruitment of small business customers, modified offer structures, proactive smart meter changeover to increase PTR take-up, modified target geographic areas and other viable options identified in stage 1.

Further details for phase 2 will be determined during phase 1.

4.5 Outcome measurement and evaluation approach

The project outcome measurement will be assessed by evaluating the extent to which the aims and objectives are met as well as meeting the project delivery milestones as outlined in the implementation approach.

Measurement and analysis of program results will be completed collaboratively with our retailer partners and are expected to include quantitative and qualitative measures such as:

- Assessment of energy and demand reductions from participating customers;
- Identification of customer experiences and preferences;
- Assessment of dispatch platform suitability and reliability;
- Assessment of tested customer incentive and acquisition strategies; and
- Identification of demand reduction density and potential effectiveness for deferral of typical network constraints.

4.6 Costs of the project

The table below shows Ausgrid’s actual project costs for 2019-2020, total project expenditure to date and the total expected project costs by the completion of the project.

Table 2 - Project Costs

Budget Item	Actual project costs 2019-2020	Total project costs as at end of June 2020	Total expected project costs
Total project costs (excl GST)	$40,786	$59,873	$1,100,000

4.7 Project Activity and Results

A full implementation proposal plan was developed in 2019-2020 with internal funding now approved. Discussions and detailed planning activities have progressed with two market providers and contracts are expected to be exchanged in order to enable commencement of trial operations for Summer 2020-21.

As part of trial development activities, in principal agreement has been reached on:

- Network support pricing structures;
- Dispatch event protocols;
- Target areas for customer acquisition;
- Dispatch platform requirements; and
- Information sharing arrangements.

4.8 Other Information

General information can be accessed from Ausgrid’s Demand Management web page from the Innovation Research and Trials link: www.ausgrid.com.au/dm

An interim report detailing the 2020-21 trial results is expected to be published on Ausgrid's website in the future.

If you have a specific information request regarding this project to assist in understanding, evaluating or reproducing this project please contact demandmanagement@ausgrid.com.au.

5 Electric Vehicle Demand Research

This project is a continuing Demand Management Innovation Allowance (DMIA) project from Ausgrid's last regulatory control period 2014-2019 into the current 2019-2024 regulatory control period. The following project report provides details of the project activities up until the end of the 2019-2020 regulatory year.

The project will be ongoing into the 2020-2021 regulatory year.

5.1 Project nature and scope

The forecast uptake of electric vehicles in Australia is still highly uncertain but the most recent forecasts from the Australian Electricity Market Operator (AEMO) estimate a potential increase from 10,000 EVs in 2020 to 630,000 in 2030 in the central scenario and as high as 2.1 million electric vehicles in 2030 in the fast change scenario. If not properly managed, the electricity demand for charging these electric vehicles may lead to significant electricity system infrastructure investments by customers, network service providers and other parties. The additional electricity demand from charging electric vehicles may also provide opportunities to improve load utilisation of existing electricity system assets or assist in balancing supply and demand due to the flexible charging and discharging of the electrical energy storage in vehicle batteries.

This project will explore the future impacts of electric vehicle (EV) charging on the Ausgrid network and the viability and customer response to various demand management interventions.

The first discovery phase of the project involved supporting an ARENA-funded project called Charge Together Phase 2 which was led by start-up company, EVenergi and supported by other partners including the EV Council, NRMA and the NSW Government. The Charge Together Phase 2 project had three main activity streams that Ausgrid supported including;

- Development of fleet products and tools to assist fleet managers to migrate their fleets to electric vehicles
- Development of private individual product and tools to assist in EV purchasing decisions
- Delivery of a private electric vehicle owners survey to inform network understanding of EV owner preferences

The second phase of the project takes lessons learned from phase 1 activities and extends research and development into two key areas;

- Participation in electric vehicle charging trials with collaborative partners, such as electricity retailers and other parties in the electric vehicle industry.
- Further investigation into the regulatory framework and options for setting and developing network tariffs in the context of electric vehicle charging in the future.

5.2 Project aims and expectations

The key objectives of the project are to:

- Understand and research options for demand management interventions using EV chargers to shift or curtail demand during peak demand periods; and
- Conduct or participate in practical, customer-based electric vehicle charging trials that explore the potential demand management solutions from partnering with customers, retailers and other EV industry participants.

Other secondary objectives include:

- Sourcing, creating and collecting activity-based customer EV data; and
- Reviewing and making recommendations on the collection of data on new demand on the network resulting from EV charging.

5.3 How and why project complies with the project criteria

This project aims to build capability and capacity in managing the electricity demand from electric vehicle charging which is forecast to be a significant electrical load in the future. Opportunities exist to manage this demand to reduce electrical infrastructure investments and to potentially use the stored electrical energy to provide network support services.

This research project is considered innovative in that it is Ausgrid's first in-depth research study into the emerging electric vehicle market in NSW and on Ausgrid's network. The modelling and research techniques utilised in the first phase of the project in conjunction with EVenergi involved an innovative bottom-up spatial and electric vehicle typology approach used to estimate and forecast the potential impacts from electric vehicle charging on Ausgrid's zone substations. This involved examining driving and charging data in combination with directly surveying electric vehicle owners to explore their perceptions about their EV usage and charging.

Insights gained from the early adopter EV owner market will provide guidance on the development of demand management options with collaborative partners in Phase 2 as well as inform all market participants on the impacts from electric vehicle charging impacts. The research provides the foundation from which Ausgrid can conduct further investigation of demand response trials with electric vehicle owner customers and to assess whether demand response activities with EV owners provide a viable option for demand reductions.

5.4 Implementation approach

The project will be conducted in two phases:

Phase 1 - Charge Together Phase 2 project support, led by EVenergi (ARENA-funded)

There are three primary activity streams for this phase of the project that was initiated in 2018-2019 and were mostly completed 2019-2020. Ausgrid supported all activities via in-kind support but principally supported the delivery of an EV owner survey and better understanding of customer preferences and behaviours. The three main activities were:

- The development of a suite of fleet products which can be provided to fleet managers with all the tools necessary to migrate their fleets to electric vehicles.
- The development of a private individual product that will provide individual EV buyers with the tools necessary to make an EV purchasing decision.
- The delivery of a private electric vehicle owners survey to inform network understanding of EV owner preferences and behaviours.

Phase 2 – Electric vehicle charging trials, EV network tariffs and EV industry engagement

The second phase of the project was approved during 2019-20 with additional project funding and involves the following key activities:

- Partnering with electricity retailers and other electric vehicle industry parties in the development and implementation of collaborative EV customer trials which explore a range of customer, network, electricity retailer and EV industry issues; and
- Engaging an economic consultant to examine the principles of network pricing and develop a network pricing framework that can be used for exploring innovative network tariffs for electric vehicle owners and electric vehicle charging network providers.

5.5 Outcome measurement and evaluation approach

The project outcome measurement will be assessed by evaluating the extent to which the aims and objectives are met as well as meeting the project delivery milestones as outlined in the implementation approach. Expected outcomes from the project include:

- Enhancing our understanding of the driving and charging patterns of EV owners by directly surveying electric vehicle owners to explore their perceptions about their EV usage and charging.
- Conducting or participating in one or more industry collaborative electric vehicle charging trials to explore a range of customer, network, electricity retailer and EV industry issues and ensure that distribution network considerations are assessed as part of the trials.
- Development and testing of network tariff options.
- Enhancing our understanding of the potential impacts of electric vehicle charging on demand through development of an electric vehicle typology approach and an assessment of demand management options at a spatial level.

5.6 Costs of the project

The table below shows Ausgrid's actual project costs for 2019-2020, total project expenditure to date and the total expected project costs by the completion of the project. All actual and projected costs are net of any partner contributions.

Table 3 - Project Costs

Budget Item	Actual project costs 2019-2020	Total project costs as at end of June 2020	Total expected project costs
Total project costs (excl GST)	$202,134	$301,378	$500,000

5.7 Project Activity and Results

5.7.1 Summary of project activity to date

The main project activity up to June 2020, included the completion of the ARENA-funded Charge Together Phase 2 component of the project. This included the completion of an online survey with electric vehicle owners in NSW to gather feedback about their opinions and perceived behaviors around their charging and driving patterns of their electric vehicles. The main objectives of this research were to:

- understand EV owners' attitudes, opinions and motivations for purchasing an electric vehicle;
- inform potential EV demand response projects and trials for Phase 2 of the project; and
- provide insights to inform an understanding of customer demand from EVs and resultant demand management opportunities.

The online survey invited electric vehicle owners sourced from a combination of the project's partners' membership networks and from selected customers in Ausgrid's database who had expressed prior interest in taking part in demand management related research.

An additional outcome of the project activity from the improved understanding of future EV demand is the development of better spatial EV forecasting tools for all market participants.

5.7.2 Update on material changes to the project

The principal changes during 2019-2020 was the further development and decision to progress with Phase 2 activities. These activities included the development of collaborative research projects with electricity retailers and other electric vehicle industry partners and engaging an economic consultant to examine potential network pricing options for electric vehicle charging.

5.7.3 Collected results

Electric Vehicle Owners Survey – Preliminary Results

The online survey was conducted between November 2019 and February 2020. The survey asked respondents questions about their EV travel patterns, where and when they preferred to charge their electric vehicle, charging equipment, tariff and interest in EV demand response trials. The preliminary results from the survey were gathered and analysed in 2019-2020 and results from the EV owners indicate that respondents:

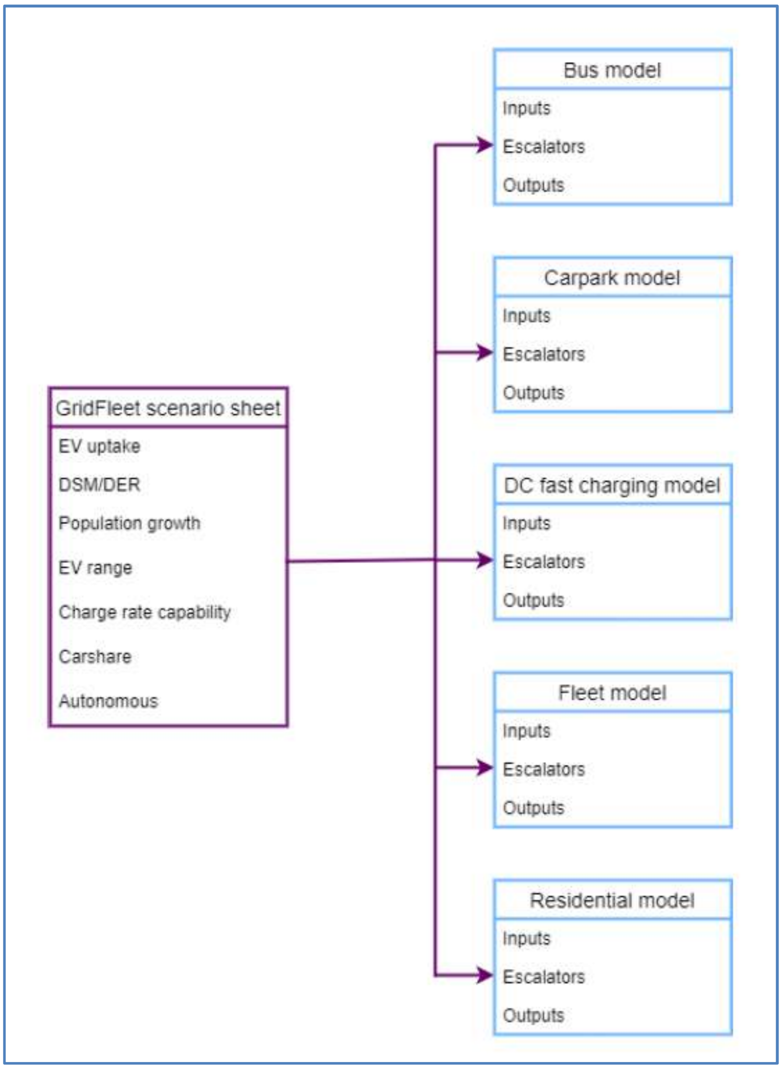
- were more likely to be living in homes, had a tertiary level of education and were families or couples without children;
- were more likely to choose to charge their EV when it was most convenient for them irrespective of the state of charge of their car battery;
- the majority would consider buying a solar system to charge their EV; and
- were interested in participating in potential electric vehicle trials in the future.

A more detailed assessment and review of the survey results are underway and will published on the Ausgrid website during 2020-2021.

EV demand typology

As part of the EVenergi project, and informed by the survey results, an EV demand typology model was developed which offers an improved understanding of the spatial demand from EVs. The model was crafted to focus at a postcode spatial level. The model developed by EVenergi as part of the project included development of five electric vehicle typologies that could be allocated at a local spatial level. The development of a local spatial allocation model allows for improved local forecasting of EV demand for use by the EV industry, market participants, networks, governments and other interested parties. The improved information will accelerate the development of EV solutions for networks, customers, markets and the industry. The below picture provides an overview of the five typology models and some of the key inputs.

Figure 3 - Typology Models Overview



5.8 Other Information

General information about the Charge Together project can be accessed on Ausgrid's Demand Management web page from the Innovation Research and Trials link: www.ausgrid.com.au/dm

This will be the location where we publish further reports and information on the project.

If you have a specific information request regarding this project to assist in understanding, evaluating or reproducing this project please contact demandmanagement@ausgrid.com.au.

6 Digital Energy Futures

This project is a continuing Demand Management Innovation Allowance (DMIA) project from Ausgrid's last regulatory control period 2014-2019 into the current 2019-2024 regulatory control period. The following project report provides details of the project activities up until the end of the 2019-2020 regulatory year.

The project will be ongoing into the 2020-2021 regulatory year.

6.1 Project nature and scope

This project is a 3-year research project being led by Monash University in which Ausgrid is a co-funding and in-kind contributor in partnership with Energy Consumers Australia and Ausnet Services. The project has been granted funding from the Australian Research Council due to its innovative combination of research techniques.

The project aims to understand and forecast changing digital lifestyle trends and their impact on future household electricity demand, including at peak times. This will be conducted by employing a range of innovative quantitative and qualitative research techniques that will investigate the behaviours and opinions and make observations of specific customer segments that are of relevance and interest to Ausgrid for better understanding how household customer demand may change in the future.

6.2 Project aims and expectations

The project has 5 key aims and objectives, which are to:

- Understand how Australian household practices (e.g. heating, cooling, entertaining) are changing and likely to change in relation to emerging digital technologies and across different electricity consumer groups.
- Identify emerging future scenarios and principles that will affect electricity sector planning in the near-medium (2025-2030) and medium-far (2030-2050) futures.
- Develop a theoretical and methodological approach to anticipate changing trends in household practices and energy demand, which brings a futures perspective to theories of social practice and digital ethnography.
- Develop an industry-relevant forecasting methodology for tracking and anticipating peak electricity demand, and energy consumption more broadly, that incorporates insights from this future-oriented social science research.
- Develop practical demand management solutions for Australian electricity network businesses to plan for efficient, cost-effective and reliable networks.

6.3 How and why project complies with the project criteria

This project aims to build demand management capability and capacity in the household customer segment by better understanding households existing and future trends in everyday household energy use practices and how effective demand management solutions can be developed for the household segment.

This research program adopts innovative approaches by applying ethnographic research techniques and sociological theories to investigate how changing social practices will impact on electricity sector planning. Expected outcomes include scenarios and principles for digital energy futures; an interdisciplinary energy demand forecasting methodology; and demand management tools to help the sector meet future residential consumption.

6.4 Implementation approach

The project will take place over 3 years and started in 2019 and will continue through to at least 2022. There are 6 stages to the project that were put forward in the ARC grant proposal:

Stage 1: Digital and energy futures analysis – to inform the ethnographic research and establish trends (Year 1, objective 1)

Stage 2: Digital ethnography with households – with consumer groups in Ausgrid's and AusNet's work areas to generate future scenarios and medium-far futures principles (Years 1 and 2, objectives 1, 2 and 3)

Stage 3: Survey supplement for ECA's annual Energy Consumer Sentiments Survey – (Years 2 and 3) objectives 1, 2 and 3

Stage 4: Scenario innovation workshops – with residential consumers in Ausgrid's and Ausnet's networks to update and extend the scenarios and principles (Year 2, objectives 1, 2 and 3)

Stage 5: Modelling and forecasting development – to cross-analyse, translate and refine the findings, and develop a forecasting methodology (Year 3, objectives 3 and 4)

Stage 6: Demand management innovation – to identify opportunities in emerging trends that are likely to impact the affordability and reliability of electricity supply for residential customers (Year 3, objective 5)

6.5 Outcome measurement and evaluation approach

The project outcome measurement will be assessed by evaluating the extent to which the aims and objectives are met as well as meeting the project delivery milestones as outlined in the implementation approach.

Expected outcomes from the project include:

- Enhancing our understanding of everyday household practices, how they are changing and how they affect household electricity consumption. (Objective 1)
- Identifying and developing future trends and scenarios in household energy use that can inform forecasting methodologies and electricity sector planning. (Objectives 2 to 4)
- Researching and developing practical demand management solutions in the household customer segment (Objective 5)

6.6 Costs of the project

The table below shows Ausgrid's actual project costs for 2019-2020, total project expenditure to date and the total expected project costs by the completion of the project.

Table 4 - Project Costs

Budget Item	Actual project costs 2019-2020	Total project costs as at end of June 2020	Total expected project costs
Total project costs (excl GST)	$174,565	$187,607	$420,000

6.7 Project Activity and Results

6.7.1 Summary of Project Activity to Date

Stage 1 completed:

Monash University has completed the digital and energy futures analysis which involved the desk-based review of 64 digital and energy industry reports from both international and local sources. This review was to gain insights on how digital technology and energy futures are envisioned and to consolidate findings and trends indicated from the reports. The findings also were synthesized into 6 speculative future scenarios.

Ausgrid's key supporting role in this stage of the project was to provide input to the industry reports to be studied, review and provide input on the speculative future scenarios being developed, verify the energy demand insights and assess from a local distributor's perspective.

Stage 2 commenced and in progress:

The recruitment survey for the stage 2 ethnographic fieldwork was conducted in March 2020 receiving over 500 responses from Ausgrid customers. The survey asked respondents questions about their energy use, the digital and energy management technologies they used in their homes and general lifestyle questions.

Ausgrid's key role in Stage 2 activities during the 2019-2020 year were:

- Sample design of customer survey to recruit a diversity of customer types to meet the customer segments being targeted for the ethnographic studies. The sample design included a diversity of household dwelling types (apartments vs houses) and locations (rural, regional and inner city).
- Preparation of customer contact lists according to the sample design
- Providing feedback and advice on the survey design in collaboration with Monash University researchers and other project partners
- Designing and testing the online survey collection tool
- Approaching Ausgrid customers by email and inviting them to the online survey
- Collecting customer consent for participation in the detailed qualitative interviews with Monash University

Results from the recruitment survey are currently being analysed and will be published, in collaboration with Monash University and other project partners, as a separate report later in 2020.

The ethnographic fieldwork to be conducted by the Monash University research team is expected to occur early in 2021.

6.7.2 Update on material changes on the project

Due to the impact of COVID-19, there was a temporary 4-month pause in the planned ethnographic fieldwork between April and August 2020. During this time work continued on the development and adaptation of the ethnographic methods for the fieldwork to account for the changed conditions posed by COVID-19, and analysis of data from the recruitment survey.

Planned activities for early 2020-21 will reflect the modification of Stage 2 ethnographic fieldwork due to the restrictions imposed by the COVID-19 pandemic on travel and face to face interactions with customers. Monash University researchers will adapt their approach by utilising video and digital ethnographic methods with 36 participants selected from the recruitment survey to conduct the in-home interviews that were originally intended to be conducted face to face.

The virtual interviews will involve detailed investigations using a variety of virtual ethnographic methods such as video recorded diaries and virtual home tours to understand participants' everyday use of technologies in their homes, how COVID-19 has impacted their everyday home routines, how they use energy and considerations around peak demand issues and their future aspirations and concerns about using energy in the future.

6.7.3 Collected Results

The final report from the Stage 1 desktop research review project was published in June 2020 and can be accessed at this link, Digital and Energy Futures Review of Industry Trends, Visions and Scenarios for the Home Report. The key outcomes from the review include:

- Six speculative 'comic strip' scenarios representing how the digital technology and energy industries anticipate everyday practices in the home may change in the future.
- An evaluation of the limitations of the future visions offered by the reports reviewed
- An innovative method for testing industry visions and scenarios with households in order to disrupt and re-imagine futures.

Analysis of results from the Stage 2 recruitment survey is ongoing and the findings are expected to be published on Ausgrid's website later in 2020. Results from the ethnographic fieldwork is also expected to be published following completion of the virtual fieldwork later in 2020.

6.8 Other Information

General information about the Digital Energy Futures project can be accessed on Ausgrid's Demand Management web page from the Innovation Research and Trials link at www.ausgrid.com.au/dm

If you have a specific information request regarding this project to assist in understanding, evaluating or reproducing this project please contact demandmanagement@ausgrid.com.au.

7 Cost Reflective Network Pricing Research

This project is a continuing Demand Management Innovation Allowance (DMIA) project from Ausgrid's last regulatory control period 2014-2019 into the current 2019-2024 regulatory control period. The following project report provides details of the project activities up until the end of the 2019-2020 regulatory year.

The project will be ongoing into the 2020-2021 regulatory year.

7.1 Project nature and scope

Ausgrid has been a leading Australian distribution network in introducing cost-reflective network pricing and introduced residential and small business time of use pricing to its customers on a large scale from as early as 2004. As at July 2018, there were 340,000 of Ausgrid's residential customers on a seasonal time of use network pricing structure and this number continues to grow. In July 2019 a monthly demand network pricing structure was introduced as the default network pricing structure for customers with new and replacement meters in Ausgrid's network under certain conditions.

The nature and scope of this project is to quantify the peak demand reduction benefits from the introduction of the new cost reflective network pricing to residential customers to better understand the effectiveness of these pricing structures as a possible targeted demand management tool for deferral of network investments. The network pricing structures under study include both seasonal time of use and monthly demand pricing structures and is focused on the residential sector for the first phases of the project. This may be extended to small business customers and the project is split into several phases as detailed in the implementation approach section.

7.2 Project aims and expectations

The aim of this project is to quantify the impact of cost reflective network pricing structures on reducing electricity demand at times of peak demand so as to develop an understanding of the complementary measures that could be used to increase the effectiveness of these network pricing signals as an effective demand management tool.

7.3 How and why the project complies with the project criteria

This project is targeted at researching and developing demand management capability by better understanding how effective cost reflective network pricing is as a demand management option to reduce long term network costs. The project is considered innovative as it employs analytical and customer surveying techniques not previously implemented to research this topic. In addition, the segment of customers being studied is considered different to other jurisdictions because of the length of time that customer's in Ausgrid's network area have been exposed to time of use network and retail pricing.

7.4 Implementation approach

The project will be conducted over several phases:

Phase 1 – Customer research and surveying

A. Customer surveying

Surveying around 1,000 residential customers and obtaining more detailed information about their appliances, socio-demographics and retail pricing plans. A follow up survey to these customers may be conducted in subsequent activities to capture a longitudinal aspect to the research.

B. Customer focus groups

Focus group research with a sample of customers from the survey to further explore their understanding of pricing plans, energy-use behaviours and responses to these pricing signals. Complementary measures would be explored in more depth during this phase. These options are currently being considered in the development of revised plans for the project.

Phase 2 – Demand reduction study and analysis

Detailed study of the impact of cost-reflective network pricing using historical data from interval and smart meter customers exposed to network time of use pricing.

This work is underway with a more detailed scope of works for ongoing activities under consideration. These activities may include monitoring of customer statistics and details of customers who are defaulted onto demand pricing from July 2019.

Phase 3 – Trial program

Trial of complementary measures identified in Phase 1 and Phase 2 that increase the effectiveness of seasonal time of use or monthly demand pricing in reducing peak demand as well as mitigating customer impacts particularly on vulnerable customers.

7.5 Outcome measurement and evaluation approach

A key preliminary outcome being measured is to quantify, where possible, the peak demand reduction effectiveness of the introduction of cost-reflective network pricing across a broad statistically significant sample of Ausgrid customers that have been exposed to these tariffs.

Evaluation of the effectiveness of pricing signals will be performed using a range of surveying and analytical techniques using customer electricity consumption data, control sample comparisons and panel methods.

The primary focus of the project will be to identify the complementary measures that can be used to increase or focus the effectiveness of these pricing signals. To achieve this outcome, a range of customer research and analytical approaches may be required.

7.6 Costs of the project

The table below shows Ausgrid's actual project costs for 2019-2020, total project expenditure to date and the total expected project costs by the completion of the project.

Table 5 - Project Costs

Budget Item	Actual project costs 2019-2020	Total project costs as at end of June 2020	Total expected project costs
Total project costs (excl GST)	$38,029	$96,700	$250,000

7.7 Project Activity and Results

7.7.1 Summary of project activity to date

The survey responses collected in June 2019 were provided to Ausgrid during the 2019-2020 period with collected results reported in section 7.7.3 below. During 2019-2020 the project activity also consisted of engaging an analytical consultant to develop the panel method analytical approach to studying the historical half hourly energy consumption data of customers on time of use network price structures. This preliminary piece of work was completed in November 2019 and is expected to be revised and adapted based on the preliminary analysis.

7.7.2 Update on material changes to the project

The most material change to the project implementation approach was an extension to the schedule for the project. This has been to:

- allow enough time to have a larger sample of customers assigned to a monthly demand pricing signals so that there is a statistically significant number of customers on a demand tariff;
- allow additional time for customers to be exposed to seasonal time of use pricing structures and so allow multiple summer and winter peak period analysis. This pricing structure was first introduced in July 2018 across Ausgrid's residential customers changing from an all-year

working and non-working weekday Peak, Shoulder and Off-Peak pricing structure to also incorporate a seasonal aspect of Summer, Winter and Shoulder months;

- Assess methods to address varying retailer application of the tariffs;
- understand how to adapt the project implementation approach and study to account for changes occurring due to the COVID pandemic; and
- develop a revised scope and plan for re-surveying customers or to conduct the detailed focus group research in a COVID safe approach (e.g. online techniques rather than face-to-face focus groups)

7.7.3 Collected results

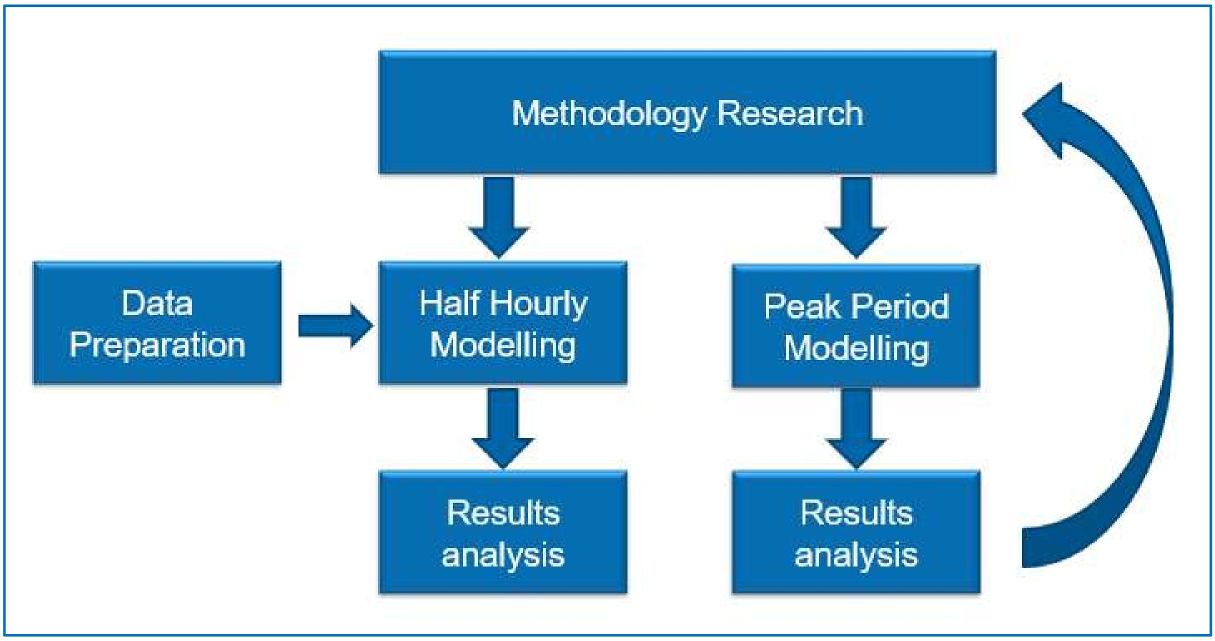
The customer survey conducted in June 2019 resulted in a total of 1100 customer responses where we collected detailed information about household energy sources and use, electrical appliances, energy efficiency, dwelling characteristics, household demographics, retail energy plans and behavioural indicators. The sample was stratified, and weightings were calculated, to allow extrapolation of results to our customer base (e.g. by linking to the ABS census data).

A preliminary analysis of the survey data has been completed to help identify complementary measures that might increase the effectiveness of the customer response to pricing signals. However, these Phase 1 activities were paused during the 2019-2020 year in order to focus on the Phase 2 quantitative analysis over the larger group of 340,000 Ausgrid customers exposed to seasonal time of use pricing.

To achieve this objective, a consultant was engaged to develop an analytical approach and to deliver preliminary results on the effectiveness of cost reflective network tariffs in reducing residential peak demand.

The approach developed by the consultant included a panel model approach to analysing a subset of customers with half-hourly electricity consumption that changed from a flat network pricing structure to a time of use network pricing structure during the period of study and a high level analysis approach is shown in the figure below. Variables included in the analytical approach were data such as the annual electricity consumption in kWh of a customer (small. medium, large), dwelling type (house/ apartment), electricity retailer, peak consumption response on typical working and non-working summer and winter days as well as the local weather conditions from the nearest weather station.

Figure 4 – Panel Model Approach



The study period used the most recent billing data available from June 2017 to August 2019. Due to the analytical approach requirement that a customer must have transitioned from a flat to a time of use network pricing structure, the sample set was limited to only 1442 customers.

The results from this preliminary study estimated that the peak demand reduction in the summer peak period ranged from 2% to 5% depending on the customer segment. The peak demand reduction in the winter peak period displayed a wider range across the customer segments with counter-intuitive results for small and medium consuming customers but a reduction of around 3% for larger consuming customers.

Improvements to the analytical approach being explored include modifications to the panel model approach or mixed models.

7.8 Other Information

General information about the Ausgrid's demand management projects can be accessed on Ausgrid's Demand Management web page from the Innovation Research and Trials link: www.ausgrid.com.au/dm

More detailed reports and findings will be released and published for this project as they are finalised and become available.

If you have a specific information request regarding this project to assist in understanding, evaluating or reproducing this project please contact demandmanagement@ausgrid.com.au.

8 Community Battery Feasibility Study and Research

This project is a continuing Demand Management Innovation Allowance (DMIA) project from Ausgrid's last regulatory control period 2014-2019 into the current 2019-2024 regulatory control period. The following project report provides details of the project activities up until the end of the 2019-2020 regulatory year.

The project will be ongoing into the 2020-2021 regulatory year.

8.1 Project nature and scope

This project aims to investigate the potential for locally based community batteries paired with an innovative business model to offer a competitive alternative to traditional local network investment, energy storage capability for market participants and introduce a novel way to markedly improve equitable access to energy storage for customers. By leveraging multiple value streams, a community battery providing network, market and customer services might be cost competitive with traditional single use network solutions in the near term.

The value streams which a community battery could leverage include:

- Providing network services to manage peak and minimum demand and power quality issues to avoid or defer traditional network investment;
- offer market participants a utility for wholesale market trading;
- provide frequency control and other grid support services; and
- offer subscribing customers a storage as a service to facilitate self-consumption of excess solar PV energy.

Battery sharing amongst networks, market participants and customers would offer both greater economies of scale and the diversity benefit of a shared asset. Shared storage services can lower costs for networks and the market which lowers costs for all consumers; and saves participating customers more than they would if they invested individually. And additional storage capacity enables increased renewable energy generation and resultant lower emissions.

The scope of this project under the DMIA includes a feasibility study into the concept by investigating the engineering, regulatory and commercial considerations as well as a customer survey to gauge customer response and attitudes towards the concept.

8.2 Project aims and expectations

The first phase of the project aims to assess engineering, regulatory and commercial aspects of the community battery concept within the National Electricity Market context via a feasibility study in the concept.

The second phase of the project aims to assess the customer response to the concept of a community battery and to better understand customers perceptions, motivations to participate and attitudes towards the concept.

The outcomes of the feasibility study and customer research will inform the potential for a practical trial of the concept in a possible phase three.

8.3 How and why project complies with the project criteria

This project aims to explore the viability of an innovative approach to meeting network needs using a blended network / non-network community storage solution. By aligning the interests of networks, markets and customers, a lower cost alternative storage solution could extend the life of local network assets and improve network reliability and power quality. Such blended solutions are uncommon with market participants, customers and networks typically acting individually as market rules and practices create barriers to effective, collaborative solutions.

The project is considered innovative in that this concept is testing how an in-front of the meter battery can be integrated into the electricity market; which has not been explored in detail by Ausgrid or within the National Electricity Market to the best of our knowledge. The engineering, regulatory, commercial and customer considerations are complex particularly within the framework of the National Electricity Market and the National Electricity Rules and this project seeks to progress the study of this innovative concept for all aspects.

For customers, this research explores a solution which both offers a possible lower-cost alternative to traditional behind the meter storage and a more equitable access to storage technology for customers unable to invest in storage at their homes.

8.4 Implementation approach

The implementation approach for this project was envisioned as 3 possible phases:

Phase 1 – Feasibility study and model business case

The first phase of the project, delivered together with specialist consultants, was to complete a feasibility study and develop a model business case for community batteries as a solution for local network constraints. The scope of work included investigation of the following aspects;

- an ***engineering*** assessment of the network need and conditions in which a community scale battery would be beneficial, including identifying various battery configurations that could be potentially viable and a short list of suppliers that could provide these options;
- an assessment of the current ***regulatory*** framework and identification of any exceptions or waivers that would be required to operate a practical trial of the concept; and
- a ***commercial*** analysis to assess the business case from a project, customer and Ausgrid perspective, determine the key drivers and benefits, and identify uncertainties and risks.

Phase 2 – Customer Research – quantitative survey

The second phase of the project included a quantitative survey of Ausgrid customers. The survey would aim to include the following aspects:

- measure consumer needs, motivations and perceptions to store Solar PV in a community battery among solar and non-solar customers;
- measure factors contributing towards purchase of batteries, among current owners and those considering a purchase;
- assess factors impacting consumer experience and performance of current batteries;
- measure profile characteristics of Solar, PV system owners in terms of demographics, household composition and socio-economic factors; and
- ascertain interest levels in future Solar PV system storage solutions (shared assets, subscription models).

Phase 3 – Community Battery pilot

The details and funding of a Phase 3 pilot program was contingent upon the outcomes from Phase 1 and internal and external review of these outcomes. Where the solution was found to be potentially viable, an implementation proposal/ plan for a community battery pilot to verify model business case assumptions on battery and market performance would be considered.

During 2019-2020, following completion of the phase one feasibility study, a decision was made to progress with a community battery pilot under Ausgrid's Network Innovation program. The community battery pilot is being developed in collaboration with Ausgrid's Network Innovation Advisory Committee (NIAC). This committee helps guide Ausgrid's network innovation activities and includes customer advocates, research bodies and environmental organisations. The NIAC were presented with the results of the phase one feasibility study and were supportive of Ausgrid progressing with a community battery pilot.

8.5 Outcome measurement and evaluation approach

The outcomes from phase one are a report that investigated and made recommendations about the community battery concept from the perspective of the engineering, regulatory and commercial issues.

To better understand the techno-economic considerations for a community battery as an alternative to network investment, outcomes from the phase one feasibility study considered the following key questions:

1. What are the technical options and costs for a community battery?

2. How do we expect the network conditions/issues to change over time?
3. What network conditions would be suitable for a community battery solution?
4. What is the potential contribution and benefits from Solar PV customer use of the community battery?
5. What are the market and system security benefits from a community battery?
6. What regulatory changes would be required to support the use of community batteries as an alternative network solution?

The outcomes from the phase 2 quantitative customer survey results will include a report that provides a summary of customer survey results and insights to better understand customers perceptions and awareness of the community battery concept and potential motivations for participating in a potential community battery pilot.

The learnings from both Phase 1 and 2 have been used to inform the progression of the project to a community pilot funded under the Ausgrid Network Innovation program.

8.6 Costs of the project

The table below shows Ausgrid's actual project costs for 2019-2020, total project expenditure to date and the total expected project costs by the completion of the project.

Table 6 - Project Costs

Budget Item	Actual project costs 2019-2020	Total project costs as at end of June 2020	Total expected project costs
Total project costs (excl GST)	$267,578	$426,555	$520,000

8.7 Project Activity and Results

8.7.1 Summary of Project Activity to Date

<u>Phase 1 – Feasibility study and model business case</u>

The project activity for phase one commenced in 2018-2019 with the release of an expression of interest for consulting services, selection of a consultant consortium and commencement of research activities. As part of the research, Ausgrid provided access to detailed network and customer data and access to a wide range of internal subject matter experts (SMEs) to inform and guide the work by the consultants.

During 2019-2020 the feasibility study was completed in February 2020. This report assessed the engineering, commercial and industry/market issues for the concept and involved three integrated workstreams; Technical, Regulatory and Commercial. To ensure alignment between these workstreams, an iterative process was adopted.

The approach to assess the feasibility included the development of several models and detailed analysis assessed iteratively in conjunction with technical, commercial and regulatory reviews of the relevant considerations that would impact the optimum outcome for all stakeholders.

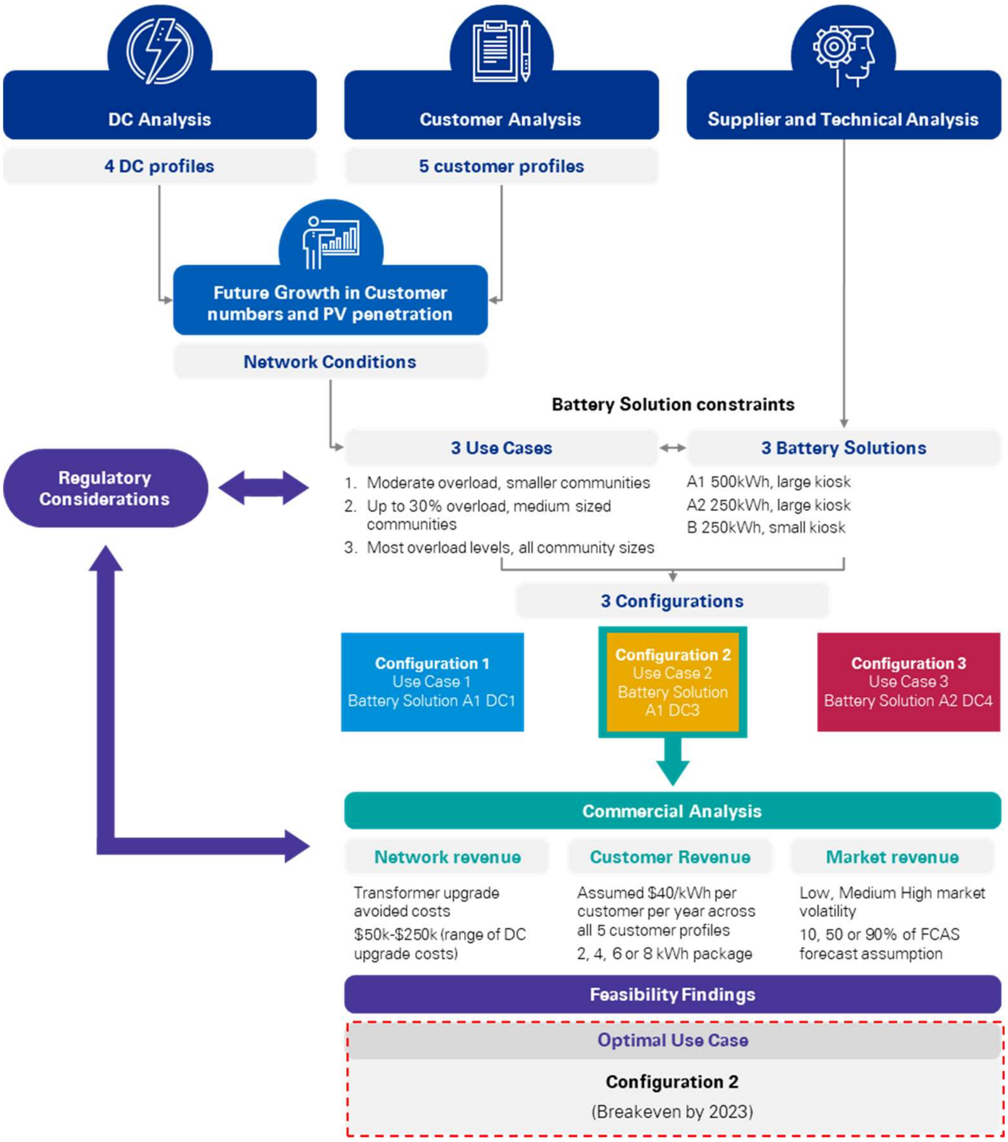
The process followed included:

- A set of technical constraints and parameters developed to establish the potential physical battery size and operational limitations, and the associated costs of various battery sizes and enclosures, in consultation with potential battery suppliers and Ausgrid network engineers.
- A selection of interval data from a representative sample of Distribution Centres (DCs) in Ausgrid's network and a representative sample of customer interval load data were analysed to develop generic DC and customer profiles. (DCs are localised electrical infrastructure at the end of the low voltage network typically serving 50-250 customers).

- The customer composition for each DC profile was determined and used to forecast potential future overload conditions that may arise due to growth in customer numbers, uptake of rooftop PV or other changes in local customer demand for electricity.
- Future network conditions were assessed to identify where a battery could offer a feasible alternative to traditional network augmentation to manage network constraints.
- Battery sizes (in kW and kWh) needed to meet the forecast Network Conditions were estimated for each DC, which resulted in a likely preferred C-rating (power to energy ratio in kW/kWh) for a battery required to manage the network constraint. C ratings are important for feasibility of battery storage, as it is a measure of the rate at which the battery can discharge stored energy and is an important factor in optimising the value of the battery.
- The network conditions identified were matched with community battery solutions established in the technical analysis to determine potential Use Cases. These Use Cases represent future networks conditions where a community battery could be feasible within technical and physical constraints, for each DC.

Significant modelling was then undertaken based upon the network need and conditions in which a community scale battery would be beneficial, which resulted in the development of three battery configurations between 250 and 500 kWh and identification of a short list of suppliers. The option models are depicted at a high level in Figure 5 following:

Figure 5 - Option Models Summary



Upon completion of pilot program plans and resolution of regulatory issues, detailed feasibility results will be published on Ausgrid's website.

Phase 2 – Customer Research – quantitative survey

During 2019-2020, the scope of the customer research was formulated, the procurement exercise completed, and a market research provider selected.

In the third and fourth quarter of 2019-2020, the online survey was designed and developed in collaboration with the market research company and input from stakeholders.

The survey design developed resulted in a targeted letter and email campaign to more than 11,000 Ausgrid customers. The survey design included:

- Existing solar PV customers segmented by annual export volume;
- Existing solar and battery customers;
- Non-solar customers; and
- Solar and non-solar customers in areas identified as representative of Distribution Centres where the community battery solution was potentially viable.

The online survey was put into field in July 2021 and results from the research will be reported in the next DMIA compliance report as well as published in a separate report on Ausgrid's website.

8.7.2 Update on material changes on the project

There was no material change to phase one of the project with some minor modifications to phase two activities considering COVID-19 impacts.

The delivery of the Phase 3 community battery pilot was transferred to the Network Innovation program, in collaboration with Ausgrid's Network Innovation Advisory Committee (NIAC).

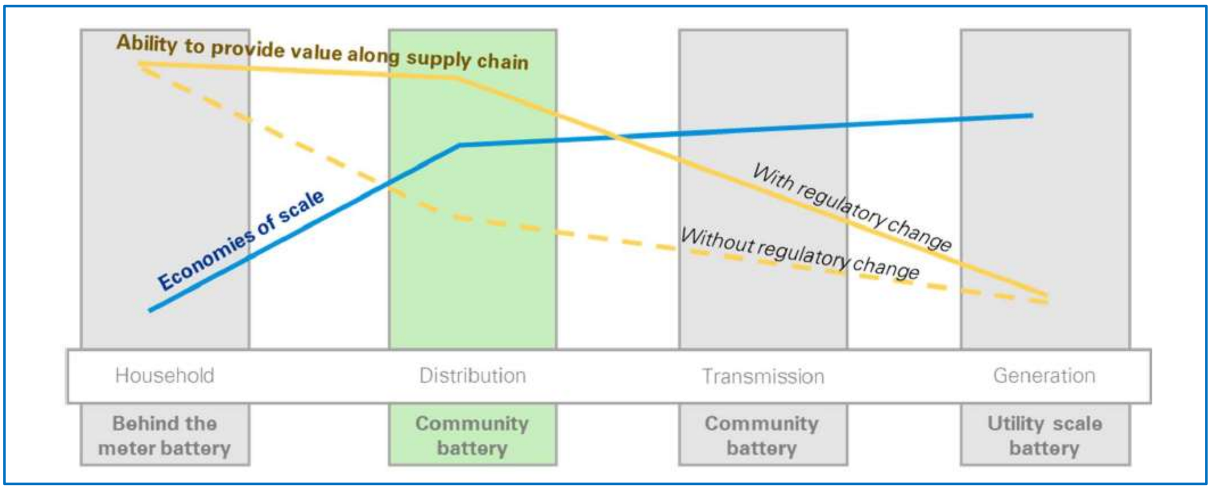
8.7.3 Collected Results

Phase 1 – Feasibility Study

The findings from the Feasibility study confirmed that the community battery concept was likely to be viable under a set of assumptions, constraints and parameters that were supported by analysis of existing network and customer data.

The Feasibility study found that a community battery located in the local distribution network has the combined advantages of capturing economies of scale whilst providing maximum value along the energy value chain. This is depicted in the concept diagram below.

Figure 6 - LV Network as location with optimal trade-off between cost and benefit of batteries



The Feasibility study was also able to identify three potential community battery solutions and their associated costs at different power to energy ratios. These costs were estimated based on consultations with a range of battery suppliers and Ausgrid network subject matter experts. We identified optimal battery size options considering installation and indirect costs, network needs and market revenue benefits.

Key risks identified by the feasibility study relate to the sensitivity of the business case to the study assumptions. These include market volatility and revenue, system security revenue, battery installation costs and future battery equipment costs. But the feasibility study did identify a number of reasonable scenarios where community battery solutions would be feasible.

The operation of a community battery pilot would test these key assumptions to help verify under what conditions a community battery is a viable, cost effective alternative to traditional network investment.

In returning to the key questions considered as part of the feasibility study, the report identified the following:

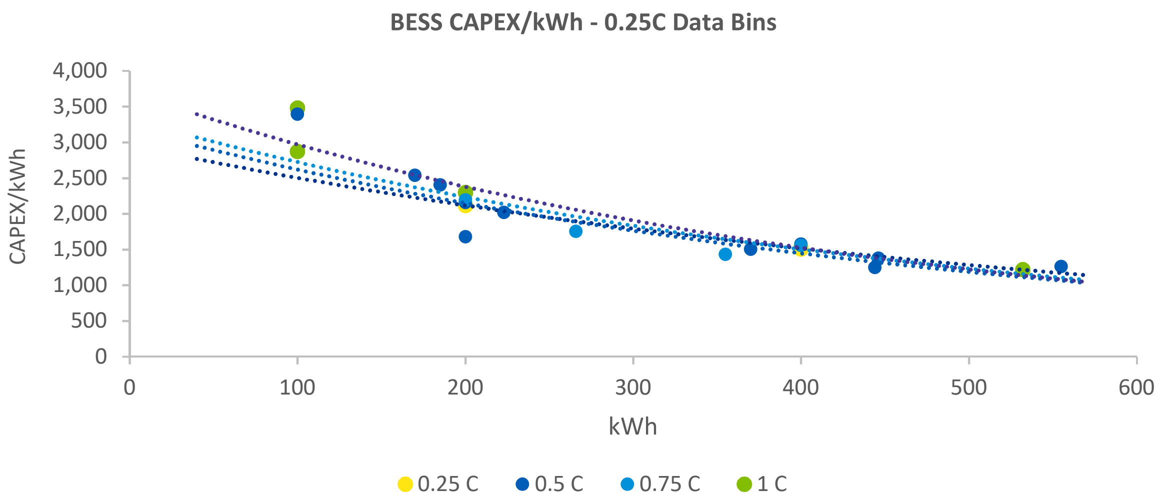
- **What are the technical options and costs for a community battery?**

For practical reasons, the size of a battery enclosure that could reasonably be connected to a distribution centre in the local community was restricted to the size of typical existing distribution centres. Distribution centres are commonly located along the roadside or in local park or open space and have a footprint that is about 3.7m by 1.8m. We assumed that locating shipping container sized enclosures (common arrangement for grid-based batteries to date) would be very challenging for most local communities and so were rejected for this assessment.

We found that the upper limit in battery capacity that would fit into a community-based enclosure would be about 500 kWh using current battery technology solutions. This battery size was found to be sufficient to manage a range of potential network constraints. With input from battery suppliers and internal and external engineering expertise, representative costs were developed for the feasibility study use cases.

The all-inclusive battery unit costs were plotted in AU$/kWh and are shown in Figure 7 below. Cost curves are based on different ranges of C ratings – or Power to Energy ratios, where the power of the inverter (in kW) is divided by the energy storage capacity in the battery (in kWh).

Figure 7 – Battery storage cost curve



- **How do we expect the network conditions/issues to change over time?**

With the forecast for growth in uptake of technologies such as solar rooftop systems and electric vehicles, the low voltage network is expected to see a significant degree of change over the coming years. Changes in the end-use appliances and behaviour of energy customers will impact the resultant conditions in the network and drive changes in future requirements. In order to understand how these network conditions might manifest in the future, it was important to understand the individual customer profiles and explore possible changes over time.

To investigate this, data analysis was performed on a selected sample of 146 DCs and the individual interval customer data served from these DCs. To help model the optimal conditions needed to support the feasibility of a community battery, several sample DC profiles, and customer profiles were created.

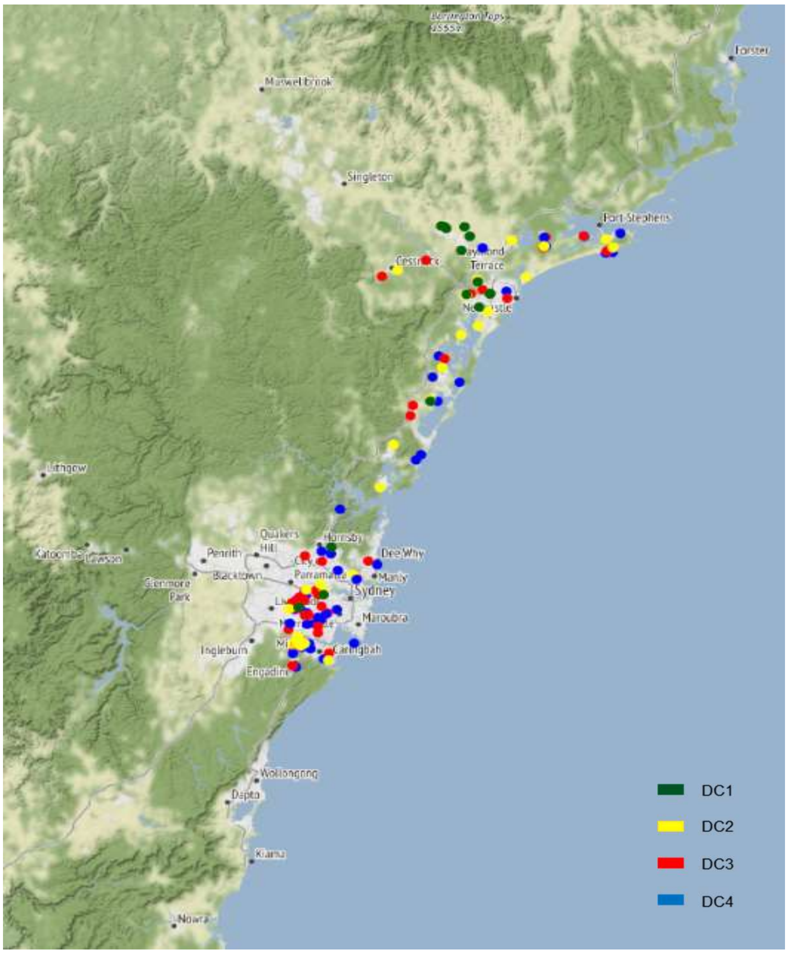
The DCs were clustered into four groups using characteristics including customer numbers per DC, average maximum demand per customer, flex ratio (defined as the max demand in peak time periods / average demand in peak time periods) and average solar system size.

The resultant DC clusters are shown in Table 7 and the distribution of the DCs in Figure 8 below.

Table 7 – Distribution centre clusters

Cluster	Average number of customers	Average max demand per customer (kW)	Average solar take-up	Average solar system size (kW)	Flex ratio
DC1	83	4.7	24%	4.1	2.96
DC2	100	3.8	24%	3.7	2.57
DC3	115	3.0	22%	3.3	2.27
DC4	127	2.4	19%	3.1	1.85

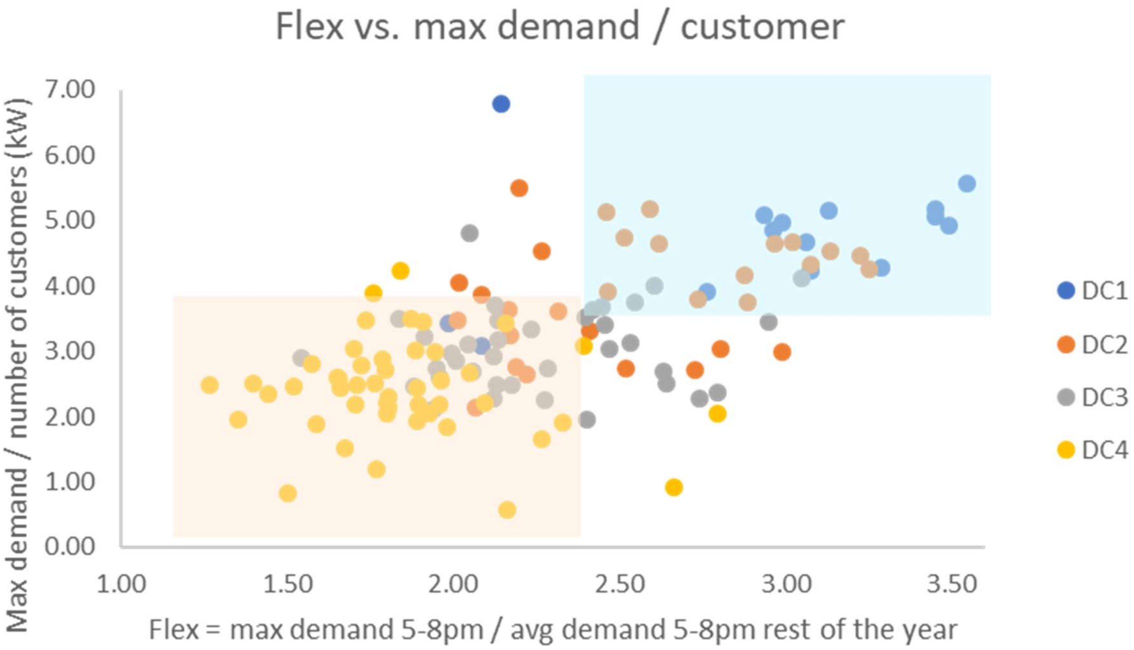
Figure 8 – Sample Distribution centre locations



The key factors that best represented the DC categories were found to be the flex ratio (ratio between the maximum energy in kWh between 5pm-8pm and the average energy between 5pm-8pm for the rest of the year) and the maximum demand in KW per customer in a year.

A plot of the sample DCs for the flex ratio and maximum demand is shown in Figure 9 below.

Figure 9 – Flex vs. Max demand per customer



The customer analysis using a K-means clustering algorithm and produced five generic customer profiles based on three key characteristics:

1. Daily energy import
2. Daily energy export
3. PV capacity

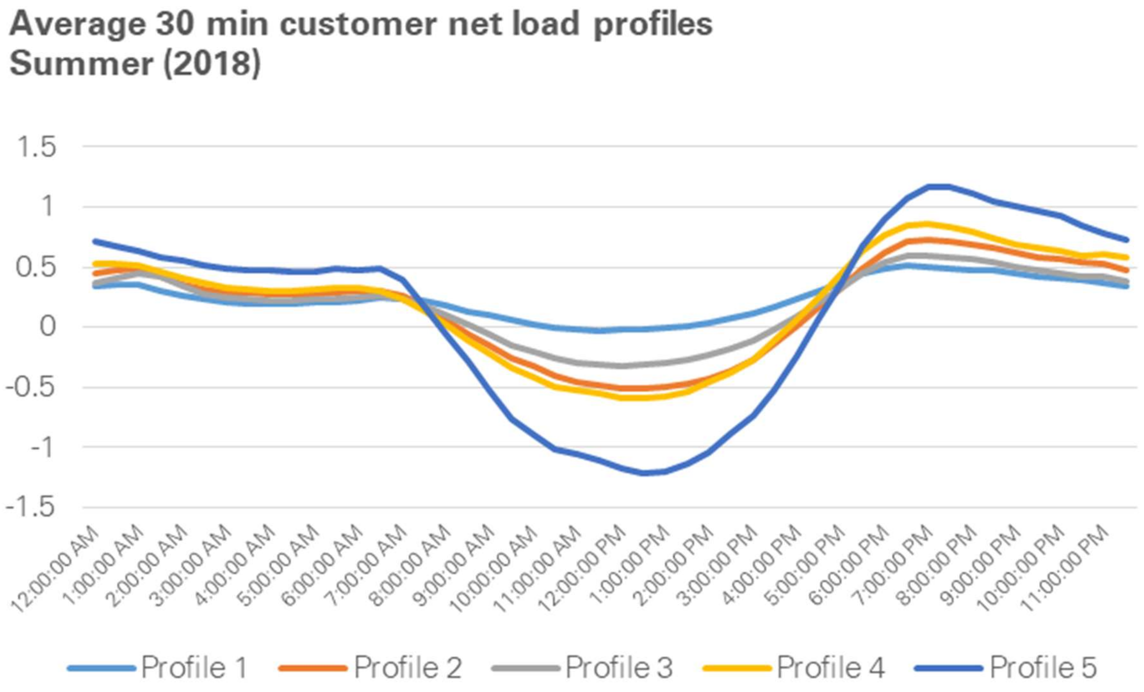
The 5 customer profiles produced by the clustering algorithm can be summarized as below. As shown in Table 8 Customer profile characteristics, the majority of customers in the dataset analysed are currently represented by Customer Profile 1 – customers with small PV systems.

Table 8 – Customer profiles

Customer profile	% of Customer base	Average Solar PV system size (kW)	Energy profile
1	48%	1.4	Low energy user
2	22%	4.7	Average energy user
3	21%	2.9	Average energy user
4	7%	6.7	Average energy user
5	2%	10.5	High energy user

The average current daily energy profiles for each customer are shown in Figure 10 below.

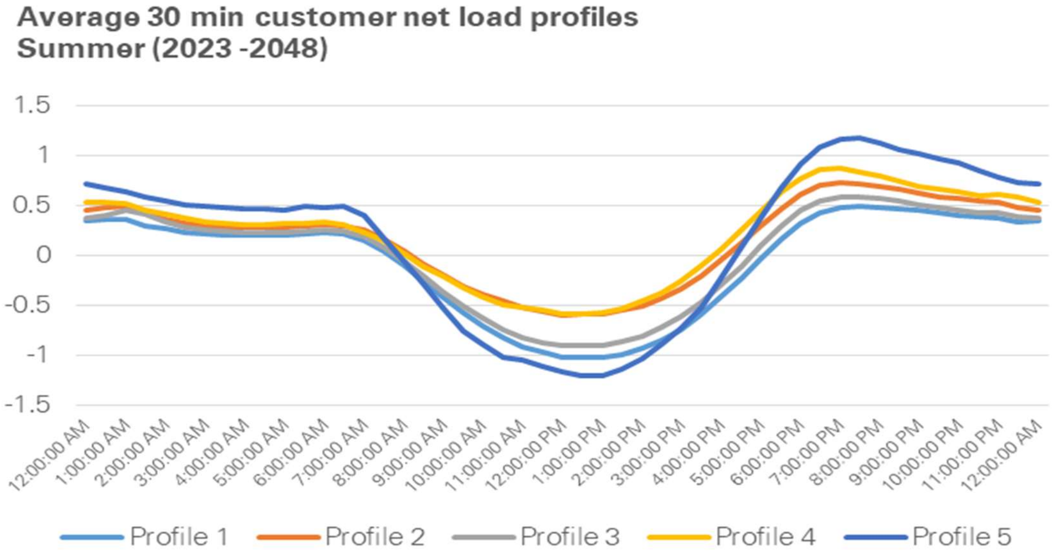
Figure 10 – Average customer profile - current



Using the above customer energy profiles, we assumed that customers with systems smaller than 5kW (Profiles 1, 2 and 3) are likely to upgrade their systems in future and hence their energy load profiles would change due to an increase in their surplus energy. To simplify the analysis, no additional changes were made at this stage. Future research might consider changes to customer load profiles due to the adoption of electric vehicles or fuel switching from gas to electric hot water heating.

The resulting future average daily net energy profiles are shown below in Figure 11.

Figure 11 – Average customer profile – future adjusted

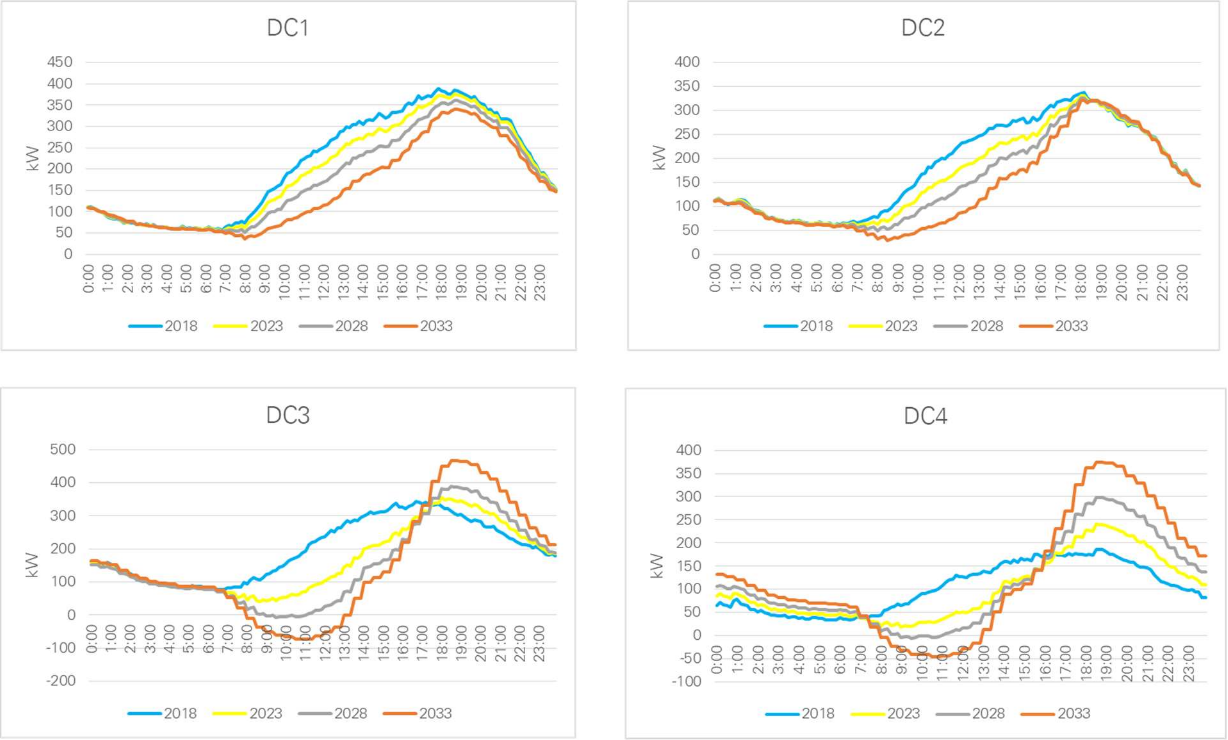


Average DC demand profiles were developed using updated numbers of solar and non-solar customers and combining their future profiles. Depending on the difference between the maximum solar and non-solar daily demand, a higher number of solar customer numbers can result in higher demand on peak days.

Combining the DC and customer profiles to project future network conditions showed that, as the number of solar customers and Solar PV sizes both increase, the forecast high demand shifts to later in the day while its duration decreases. This implies that, over time, the hours of storage in the battery that would be needed to avoid overload decreases – hence the cost of the battery to fulfil the network need would decrease.

The average DC profiles shown in Figure 12 below were used to inform potential future community battery sizes required to manage local network constraints.

Figure 12 – Average Distribution Centre Demand Profile – future years



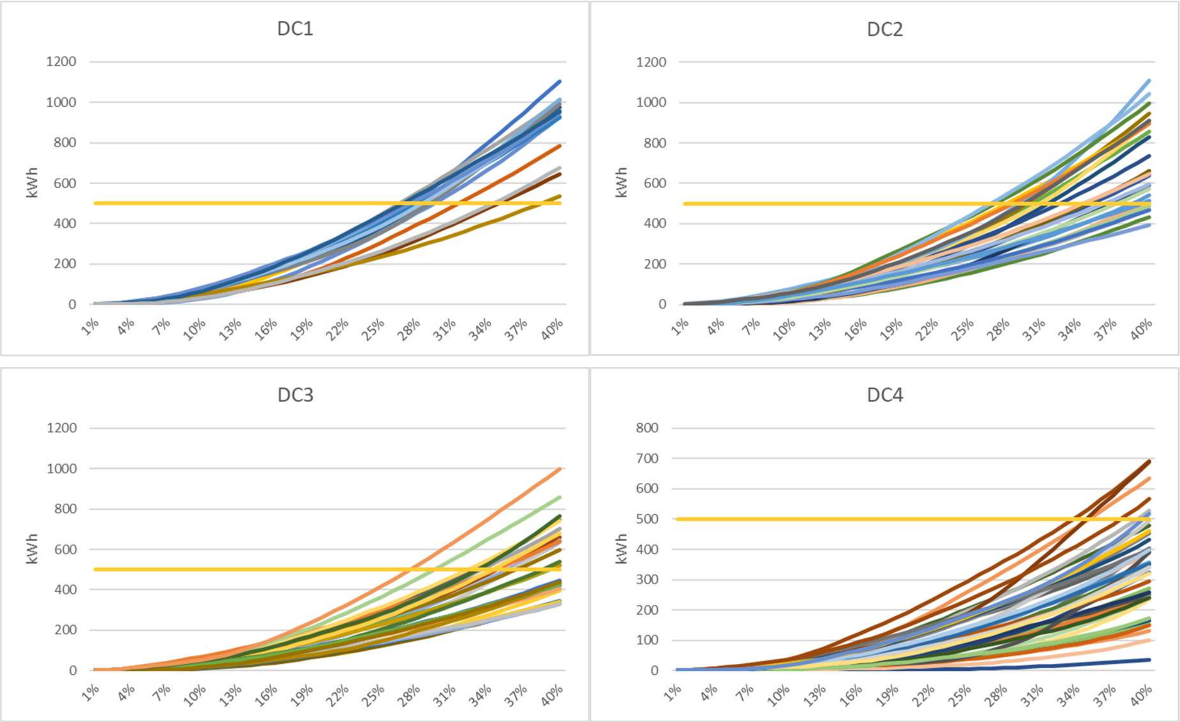
- **What network conditions would be suitable for a community battery solution?**

For the purposes of the study, and as noted above, we assumed that the upper limit for an individual battery to fit into an enclosure would be 500kWh, considering current technology. And while it might be possible to install a second battery should sufficient space be available, for the purposes of simplification only single installations in a DC were considered. Likewise, in the future, as battery technology develops, it may be possible to fit more than 500kWh into the same enclosure, but this was not considered for future scenarios as a part of this study.

Load curves for each DC cluster were taken into consideration to understand the limitations of a 500kWh single battery. The analysis indicates that batteries could service different DC clusters for different combinations of number of customers and overload percentage, as shown in Figure 13.

This analysis indicates that while there is a wide variation in the required battery size to manage a range of overload conditions, a 500kWh battery on its own had the potential to address overload conditions of over 30-40% for many DCs assessed as part of this research.

Figure 13 – Overload vs Battery Size (500kWh, 'yellow line')



- **What is the potential contribution and benefits from Solar PV customer use of the community battery?**

The purpose of this part of the research was to understand the contribution of customers to the overall economics of the battery, and the portion of the battery storage capacity that would need to be retained for customer use.

In order to design a draft battery package for customers, the impact of different approaches on estimated customer savings was analysed. This was driven by a customer's retail tariff and the energy banking methodology.

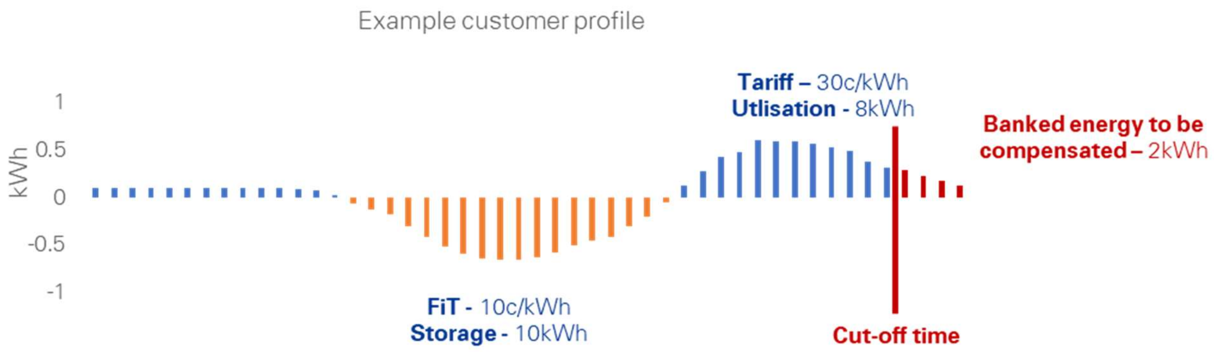
We compared the cost savings of a customer under the Community Battery Initiative against their current retail offer. A list of current retail plans offered to customers in Ausgrid's network was compiled and filtered by the cheapest offer available by retailer and tariff type (Flat and Time-of-Use). We then assumed the weighted average price according to each retailer's market share in the NSW electricity retail market, as seen in Table 9 below.

Table 9 – Weight average retail tariffs

Tariff Type	Daily supply (c/day)	Flat Charge (c/kWh)	Peak (c/kWh)	Off-peak (c/kWh)	Shoulder (c/kWh)	FiT (c/kWh)
Time of use	95.98		45.32	19.53	25.75	11.14
Flat	85.46	27.63				10.94

For the purposes of this study, we did not consider the potential impact of assuming a Demand Tariff versus a Time-of-Use Tariff. We note that although Demand Tariffs have been introduced, there are few offers in the market and customer adoption of this tariff is still in its infancy. It was therefore excluded from the analysis in this study.

The energy banking methodology is also an important consideration in capturing the value of energy storage for customers. Depending on the amount of storage a customer signs up for, some customers might not consume all the energy they export on the same day. Therefore, an appropriate compensation mechanism would need to be put into place to ensure that customers do not forfeit the FiT they would have received for any surplus energy exported and not used within the cut-off time.



A range of energy banking options were considered as described in Figure 14 below.

Figure 14 – Energy banking options

Methodology	Description
Energy Storage Cap	• Customers are entitled to bank energy up to a certain limit (e.g. 5kWh) • Banked energy (up to the cap) carries forward indefinitely • Limits cost savings for customers with high net exports and low imports but maximises savings for customers with profiles that lag over some days
Reset	• Banked energy is reset to zero at a designated time period, e.g. at midnight and customers need to be compensated for any surplus banked energy • Ultimately limits the value of the Community Battery Initiative to customers whose profile typically results in surplus banked energy at the end of the reset period – unless a higher FiT was offered to the customer compared to the retailer
Uncapped	• Banked energy is carried forward indefinitely until there are sufficient imports to discharge • There is no limit on banked energy which may be carried forward – this is equivalent to the maximum potential energy savings
Rolling Reset	• Banked energy must be discharged within a designated time from the time at which that energy is banked. • For example, 1kWh banked at 2pm, must be discharged within 24 hours (by 2pm the following day) otherwise the banked energy is lost

In general, the longer the reset period the higher the average customer savings, which is due to the fact that customers are allowed more time to import the stored energy and capture the value of their export energy in the absence of additional compensation for surplus banked energy.

But for simplicity and to align with existing settlement processes, it was decided that a daily reset at Midnight on stored energy could be incorporated easily into AEMO's current settlement process. Customers are assumed to store up to their energy storage limit in a day and import their stored energy during the same day. At midnight, the energy storage limit resets to zero. On days where the customer exports more than their allocated storage package, surplus export energy would still be sold via their retailer.

It is anticipated that a range of models could emerge where the Battery Operator could trade customers' energy in the market on their behalf. However, this would require a more thorough understanding of customer behaviour and its impact on the optimum operating model. For these reasons, it is envisaged that the first step in assessing the concept for a community battery would be a simpler business model, where the energy is reset daily.

Similarly, a community battery subscription or service charge was simplified for ease of analysis with flat annual charges of $25/kWh to $40/kWh considered. These estimates were based on a percentage of the arbitrage value available to a customer on a time of use tariff.

Furthermore, for the analysis, the available battery subscription sizes were set at 2, 4, 6 and 8 kWh of energy storage per day. These sizes were sufficient for all but a small number of customers.

For each customer profile, the optimum package size that would achieve the optimum utilisation of the subscribed battery storage capacity was determined. The Battery Service Charge was assumed to be $40/kWh per year for this analysis. This was determined on the basis that all customer profiles were able to cover the cost of battery charge for their optimal package size, out of estimated energy savings. This would mean that all customers signing up to the Community Battery Initiative would capture a net savings in their energy bill after paying the Battery Service Charge.

Table 10 – Estimated customer profile savings (future)

Customer profile	Assumed solar system size (kW)	Battery package size (kWh)	Annual customer savings (at $40/kWh)
1	5	6	$156
2	5	6	$128
3	5	6	$132
4	6.7	6	$115
5	10.5	8	$216

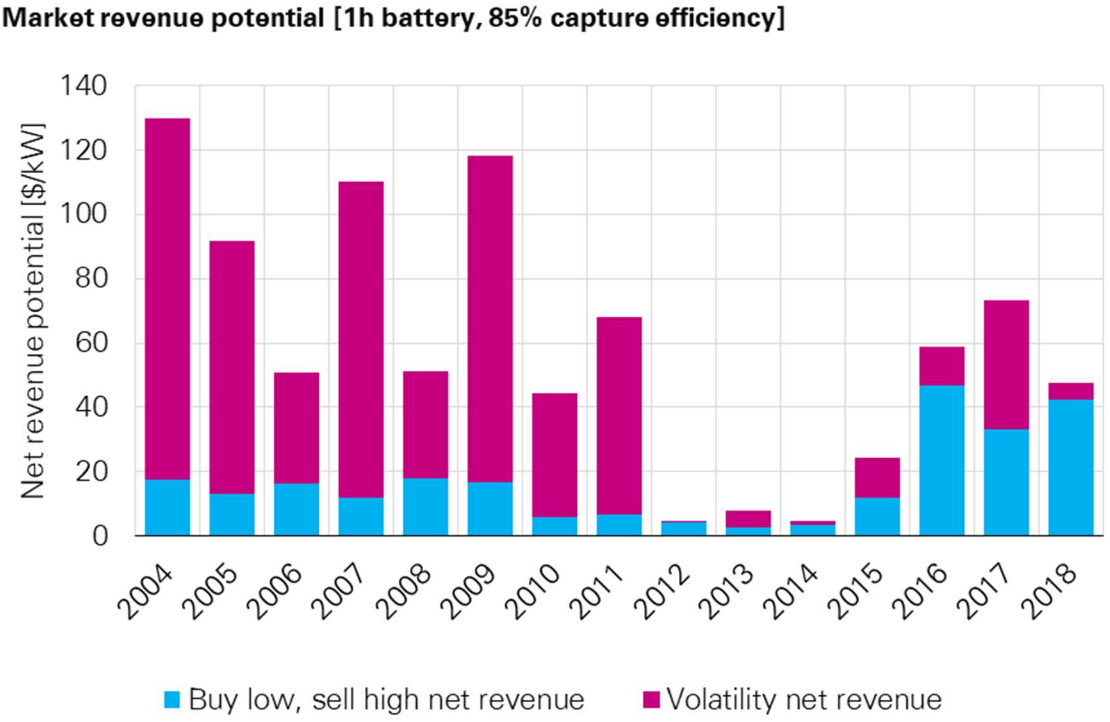
- **What are the market and system security benefits from a community battery?**

A key revenue source for a community battery is wholesale market revenue which can be generated using the battery capacity when it is not utilised by customers. Based on current market reforms under consideration and the extent of investment across the market, forecast wholesale market conditions (spread and volatility) are very uncertain. To this end a range of market outcomes have been tested to reflect the potential variability in market revenue potential.

Two possible sources of revenue were considered; market arbitrage revenue and Frequency Control Ancillary Services (FCAS) revenue.

An arbitrage model was used to estimate the potential wholesale market revenue for the battery. Market revenue from arbitrage relies heavily on market volatility which has been highly variable in the past. Figure 15 below shows the potential net revenue a 1h battery could have generated under different historical volatility assumptions in NSW.

Figure 15 Market revenue potential



Additional ancillary service revenue can assist the business case but is also difficult to forecast and not readily bankable under current Rules. The total value of the historical FCAS market is shown in Figures 16 and 17 below.

Figure 16: NSW Regulation FCAS market historical data

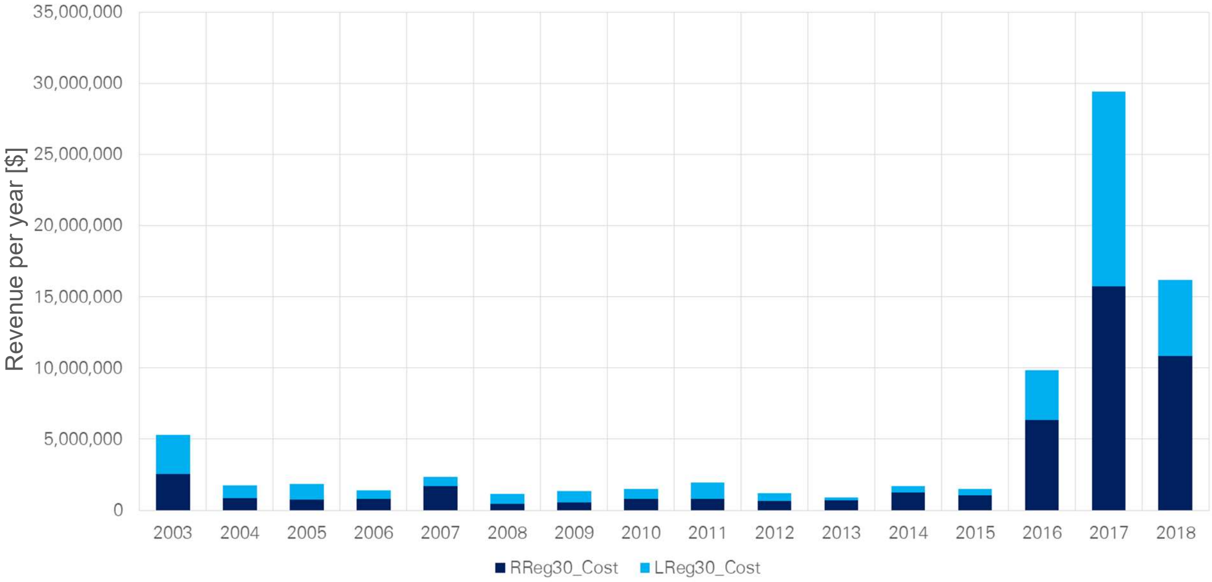
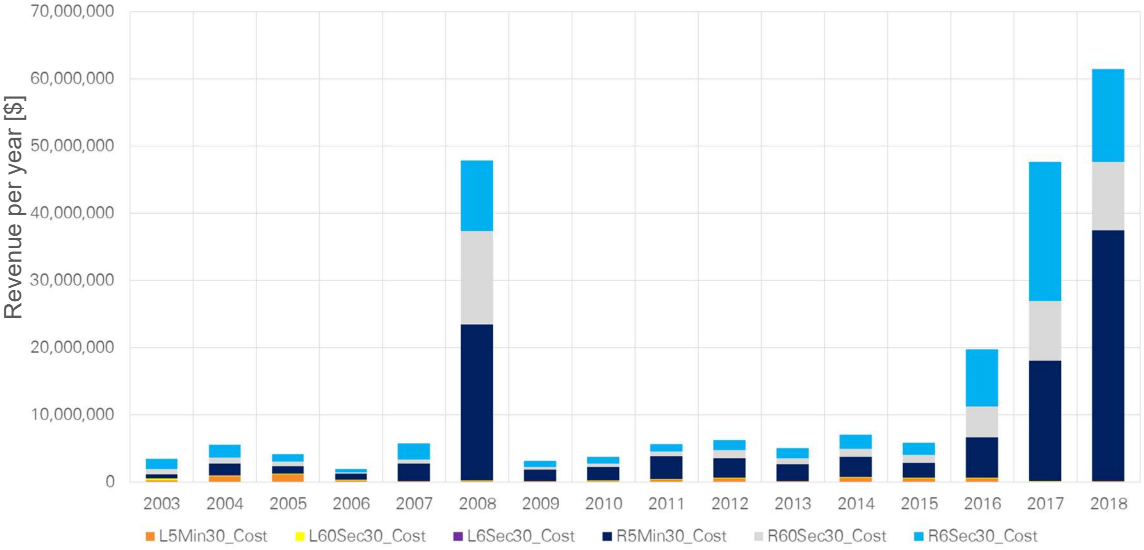


Figure 17 : NSW Contingency FCAS market historical data



For the purposes of our assessment, the following assumptions were made:

For market revenue:

2017 – Base Case	Average daily spread and average volatility
2007 – High	Flat daily spread and high volatility
2018 – Low	High daily spread and low volatility

Assuming battery C-rating of 0.8 and a capture efficiency of 85%, including daily spread and high-priced events, the market revenue in these years was:

2017 – Base Case	$79/kW
2007 – High	$144/kW
2018 – Low	$55/kW

Daily spread was based on running the battery for 1 full cycle (1.25h charge and 1.25h discharge) or 2 full cycles (2.5h charge and 2.5h discharge) per day, such that the total number of cycles is capped at 400 per annum (6000 over 15 years), to maintain the life of the battery.

For FCAS revenue, the analysis considered two sources of historical FCAS market revenues in order to develop assumptions for annual FCAS revenue.

- *Independent Energy Research* – Independent energy market forecast estimates average annual FCAS revenue to be approximately $133/kW. This reflects an average across both contingency and regulation FCAS revenue.
- *Historical FCAS market data* – Historical data for the total annual FCAS market revenue (for each contingency and regulation services) and the corresponding available capacity in 2018 was extracted to calculate the average annual $/kW FCAS revenue.:

For the purposes of this assessment, the following assumptions were made:

Base case scenario:	$43/kW pa (50% of Historical FCAS market value)
Sensitivity (low):	$9/kW pa (10% of Historical FCAS value)
Sensitivity (high):	$120/kW pa (90% of Independent energy market forecast value)

- **What regulatory changes would be required to support the use of community batteries as an alternative network solution?**

The Community Battery Initiative is an example of a Multi-Use Application (MUA) in the energy market. MUAs are those where a single energy resource or facility provides multiple services to several entities with compensation received through different revenue streams. While optimising and combining these various revenue streams improves the economics of the projects, this can lead to substantial challenges for the regulatory framework. This is especially the case for community batteries which would be providing both regulated and competitive services.

Changes required are likely to relate not only to the National Electricity Rules but also to methodologies and procedures applied by both the AER and AEMO. There may also be a need to amend some aspects of the jurisdictional requirements.

Some of the required changes are:

- Customer energy flows to and from the battery are treated separately to market energy flows, effectively netting out the community battery volumes from settlement in the wholesale market. This would avoid double payment by customers for energy stored in the battery and imported back to the household via the same meter used to measure energy import via their existing retailer.
- AEMO market specification to provide reasonable access of community batteries to FCAS market plus the wholesale market. This would remove any barriers to capturing these revenue streams.
- The development of an efficient and equitable network tariff to levy on flows to and from the community battery. This avoids the application of inappropriate network tariffs which do not reflect the impact of such flows on the distribution network or may not reflect the long run marginal costs of providing the service.

We note that some of the proposed changes would also help facilitate other models of DER and decentralised energy, as well as future market design changes such as peer to peer transactions.

The advantage of a community battery is that the total capital investment across the supply chain is significantly lower than installing single purpose battery storage (i.e. aggregation of home batteries, network support battery, or an energy arbitrage battery). The objective of the regulatory arrangements is to recognise and optimise this advantage in a manner which promotes efficiency, maintains network security and protects customers.

The overall viability of the community battery concept would depend on optimising the revenue across the multiple value streams. This will depend on balancing the use of the battery for the network, customers and wholesale market, taking the network constraint and the nature of the service offered to the customers into account.

For the purposes of this study, three separate configurations were tested, combining the following battery solutions and network Use Cases.

Table 11 – Use case definitions

Use case Configuration	Distribution centre type	Customer numbers	Battery size (kWh)
1	DC1	70	500
2	DC2	120	500
	DC3	160	500
3	DC4	150	250

In terms of dispatch hierarchy, the following was assumed:

1. Network Service: It is assumed that the operation of the battery will be restricted in such a manner as to ensure that the battery is available to meet any network overload conditions, which is expected to occur on a limited amount of days per year.

2. Customer Use: The Battery Operator will need to ensure that any amount of energy stored in the battery by the participating customers is available for dispatch to customers within the assumed 24h reset period.
3. Wholesale Market Trading: The battery will be available to allow a market participant to take advantage of arbitrage and FCAS ancillary service opportunities in the NEM.

Note that customer and wholesale market trading operations may change over time and depending on commercial arrangements.

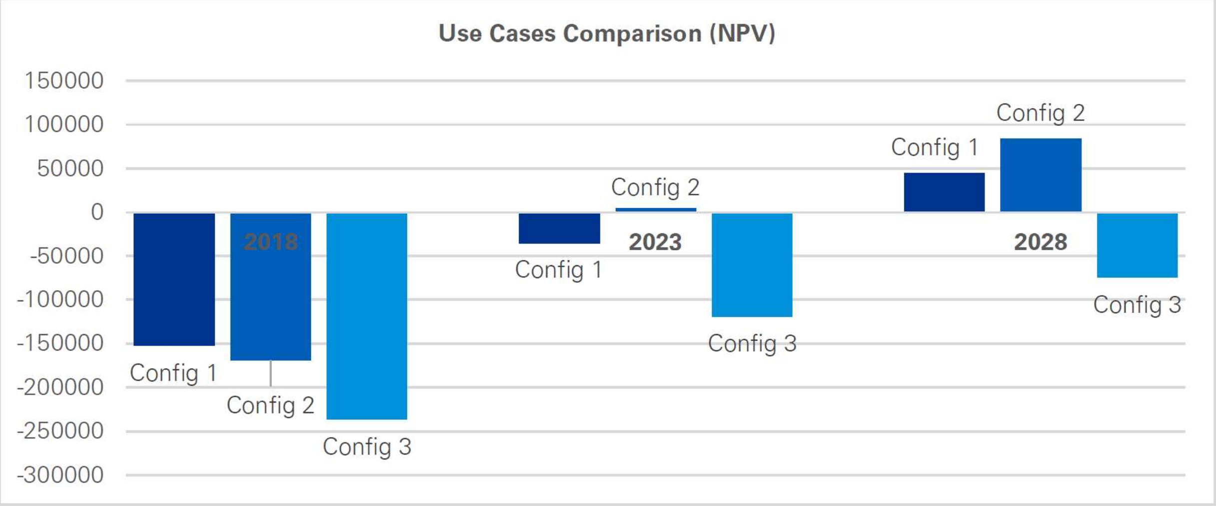
In addition to assumptions detailed elsewhere, some other assumptions used for the modelling are as per Table 12 below.

Table 12 – Model assumptions

Assumption	Value	Units
Network investment	50-250,000	$
Network asset life	45	years
Battery asset life	15	years
Pre-tax real cost of capital	3.5	%
O&M costs	10,000	$ pa
Battery depth of discharge	95	%
Battery degradation rate	2.5	%pa
Battery round trip efficiency	88	%

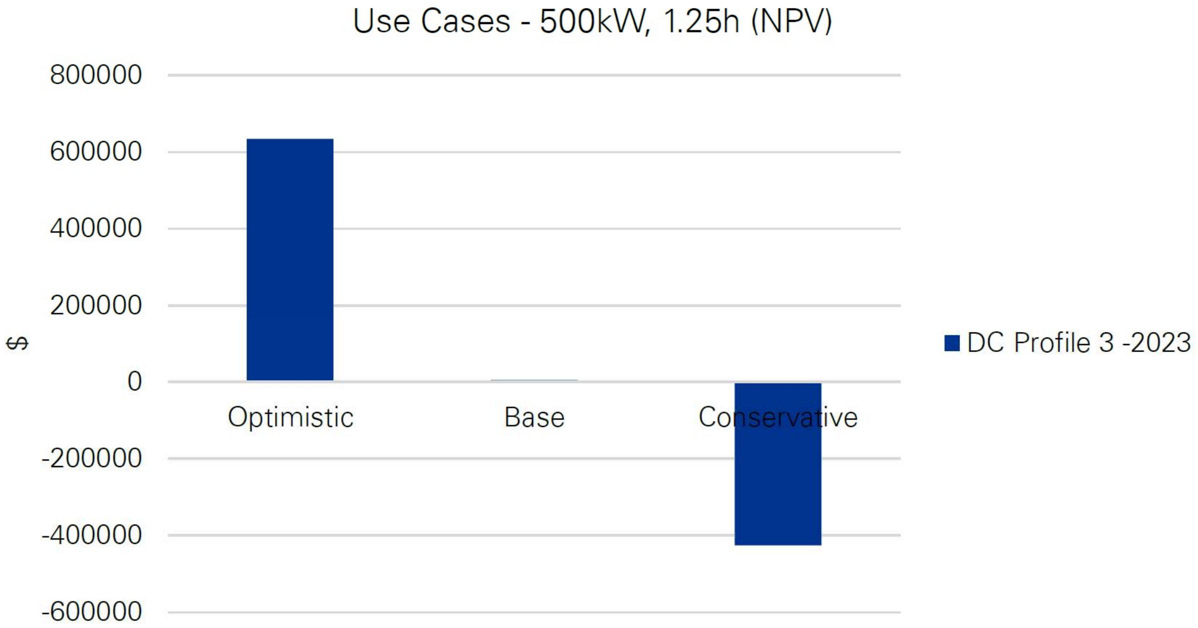
The charts below show the results for the base case for a $250,000 network investment for Configurations 1 and 2 and a $125,000 network investment for Configuration 3. Configuration 2 is shown to offer a positive NPV by 2023, while Configuration 1 has a positive NPV by 2028.

Figure 18 : Base case, NPV comparison



Looking more closely at Configuration type 2 in 2023, the sensitivity analysis shows that the NPV in 2023 ranges from over $600,000 under more optimistic assumptions to -$400,000 under more conservative assumptions. See Figure 19 below.

Figure 19 : Configuration 2 sensitivity analysis



Discussion

The results identified a number of potential near future scenarios where a community battery would offer a cost competitive alternative to traditional network solutions. The research also highlighted the uncertainty associated with a range of assumptions and identified some of the elements that might be properly tested in a pilot trial of the concept. These might include the:

- actual costs associated with the installation and operation of a locally based community battery;
- performance and value derived from network support operation of the battery;
- the impact on power quality, voltage control and other grid support benefits;
- relative use, timing and value of customer energy exports and imports;
- customer response to a battery services offer;
- impact of changes in retail and network tariffs on customer savings and uptake;
- the impact of time of day settlement of customer stored and dispatched energy on the market revenue capture and overall economics of the battery;
- preferred commercial model from the battery operator's perspective;
- conflicting dispatch priorities and resulting opportunity costs;
- level of flexibility required in the operating model to adequately manage risk;
- actual performance and value derived from market operation of the battery; and
- performance of the shared resource to deliver network, customer and market benefits.

as well as a range of other network, customer and market issues.

Phase 2 – Online Customer Survey

Following the development of the online survey towards the end of 2019-2020, preliminary results from the analysis were run in the first couple of weeks of 2020-2021 providing initial but valuable actionable insights for the project. Some of the key insights include:

- most customers were initially unaware of any possible options for storing solar apart from their own battery, with no differences between those with or without solar, nor with or without a battery;

- respondents were more likely to be aware of the *term "community battery"* than the concept of how it worked;
- when provided with information explaining what a community battery was and how it operated, there was a **strong level of interest among customers** towards the concept of a community battery in general;
- most customers indicated they would **sign up if the opportunity arose** in their area and it was affordable to them, especially pre-registered participants, non-battery owners and large exporters; and
- the availability of a local community batteries could see a boost in the take-up of solar PV and a drop in home battery installations.

Results from the customer online survey will be compiled and published on Ausgrid's website during 2020-2021.

As part of the Phase 3 community battery pilot, additional customer research via online forums is scheduled to be conducted to explore in more depth a range of specific customer propositions and characteristic profiles of each of the key customer segments for the pilot. The online forum will enable customer testing and verification of specific messages, community engagement and product offering elements before the launch of the pilot. Further information on the community battery pilot will be published on Ausgrid's website in future.

8.8 Other Information

For further general information about the Ausgrid Community Battery project can be accessed on Ausgrid's website at https://www.ausgrid.com.au/In-your-community/Community-Batteries. DMIA research results will be published at www.ausgrid.com.au/dm.

If you have a specific information request regarding this project to assist in understanding, evaluating or reproducing this project please contact innovation@ausgrid.com.au.

9 Power2U – Solar and Lighting Incentives Program (Demand Management for Replacement Needs)

This project is a continuing Demand Management Innovation Allowance (DMIA) project from Ausgrid's last regulatory control period 2014-2019 into the current 2019-2024 regulatory control period. The following project report provides details of the project activities up until the end of the 2019-2020 regulatory year.

The project will be ongoing into the 2020-2021 regulatory year.

9.1 Project nature and scope

This project aims to test the viability of using non-network options to defer or manage the load at risk associated with network investments that involve retiring / replacing aged assets. Around 90% of Ausgrid's capital investment expenditure over the next 5-10 years is related to the retirement / replacement of aged assets and this will be an important project in building demand management capability for this type of application.

This project focusses on developing a solar and energy efficiency incentive program that explores seeking permanent demand reductions that can be attained through a market-led approach. By targeting small geographic areas representative of a network replacement need, this project expands on previous applications of demand reduction by contemplating what is required to defer aged asset replacement. In this instance, the demand reduction must be both geographically located in the service area of a network need, and be capable of delivering demand reduction over a long duration in order to reduce the risk posed by an aged asset failure rather than a network overload and thereby defer the investment required to replace aged assets.

This project is co-funded with the Australian Renewable Energy Agency (ARENA) and the City of Sydney.

9.2 Project aims and expectations

The project originally set out to explore two key objectives, as well as several secondary objectives as stated below.

- Test the effectiveness of incentives to market providers in a targeted geographic area that lead to new installations of technologies that offer permanent demand reductions (e.g. solar power and energy efficiency). This trial is aimed to test whether targeted incentives can create additional customer activity (i.e. above business as usual).
- Study the viability of traditional demand response options to manage load at risk in the event of a network outage. This objective would be more focused on exploring the potential of using customer generation, battery storage, load shedding or other flexible demand response options for longer durations typical of a network outage scenario.

Secondary objectives include:

- Identification of strategies to build effective solution portfolios to manage risk;
- Policy and contract mechanisms to support agreed non-network solutions with customers; and
- Identification of connection process changes to improve customer outcomes.

9.3 How and why project complies with the project criteria

This project aims to build demand management capability and capacity by exploring solutions targeted at non-network options that defer or manage the load at risk associated with network investments that involve retiring / replacing aged assets. Using non-network solutions to manage risk from replacement driven investments differs markedly from typical overload risk.

The project aims to investigate an innovative approach to build a portfolio of permanent and temporary load reductions across the daily profile and is considered innovative in that applying demand management solutions to address aged asset related network investments is a new and emerging application of demand management.

9.4 Implementation approach

The project will be conducted in three phases:

Phase 1: Market engagement and provider selection – invite submissions/proposals from market to clarify specific trial operational issues and select preferred project partners. Establish service contracts with market providers and project partners. Completed in 2018-2019.

Phase 2: Initiate and operate trial activities over a period sufficient to allow the market to develop and deliver outcomes (est. 18 to 24-month period).

Phase 3: Assessment of trial objectives with project partners, reporting and sharing of lessons learned.

9.5 Outcome measurement and evaluation approach

One of the key objectives of the project is to seek to establish what additional uptake of permanent demand reducing technologies, such as solar PV and energy-efficient lighting upgrades, is generated by providing incentives to market providers in targeted geographic areas over a limited period. This will be evaluated by measuring the total take up from the incentive program and comparing to the background and forecast rate of uptake of solar and energy efficiency activities in the target areas estimated in the absence of any incentives.

Other outcomes that will be measured and evaluated may include:

- Comparisons between the different approaches to targeting a geographic area. For example, target areas with one market provider versus areas with multiple providers competing for customer sales;
- The effectiveness of differing incentive values provided to market participants;
- Whether the incentive passed onto customers by market providers, whether in full or in part, was considered material to the customer decision-making process to invest in solar and energy efficiency and hence effective as an incentive;
- Whether the incentives provided, and approaches taken, would provide enough material change to the electricity demand in a targeted area to influence a typical network investment decision;
- How cost-effective the demand reductions are on a $ per kW or $ per MWh basis;
- What other market barriers or issues are experienced by the market providers in getting customers to invest in solar or energy efficiency technologies (e.g. premise ownership) and any insights on how to address these barriers; and
- Any other feedback from market providers that may assist in understanding how to improve targeted incentive programs similar to Power2U. This may include why or why not customer sales were made, what worked or didn't work effectively for different customer segments.

The second key objective was to understand whether traditional demand response techniques could be adapted and be an effective part of non-network solution to an aged asset replacement network investment. This was intended to be measured and evaluated by conducting customer research to explore whether demand response techniques could be used to address an outage scenario that might typically be longer in duration.

9.6 Costs of the project

The table below shows Ausgrid's actual project costs for 2019-2020, total project expenditure to date and the total expected project costs by the completion of the project. All actual and projected costs are net of partner contributions.

Table 13 - Project Costs

Budget Item	Actual project costs 2019-2020	Total project costs as at end of June 2020	Total expected project costs
Total project costs (excl GST)	$311,450	$952,208	$1,300,000

9.7 Project Activity and Results

9.7.1 Summary of project activity to date

Phase 1 market engagement and provider selection has been completed. Phase 2 is underway, with market providers operating in all project areas. One Market Provider completed their involvement in the project at the end of this 2019-2020 reporting period.

9.7.2 Update on material changes to the project

This project has been expanded and extended in order to fully test the original objectives and in response to early trial results. Notably, Phase 2 project activities took longer to commence than anticipated, and in order to allow the incentive offer to extend over a period of about 18-24 months, phase 2 activities were extended.

In response to preliminary results and feedback from market providers, the number of market providers operating in trial area two was increased from two to five and the geographic area for this trial area was increased in size.

Also, in response to preliminary results, the incentive level applied to trial area one was increased to align with that offered in trial area two.

The decision to proceed with the second objective to conduct customer research to explore longer duration demand response has been deferred and will be reassessed once more complete results from the incentive trials are complete.

9.7.3 Collected results

Phase 1 was initiated with the publication of a Request for Information document seeking the views and opinions from industry representing a range of energy efficiency solutions. Analysis of the industry feedback resulted in the selection of Solar PV and energy efficient lighting as the incentivised technologies. These were selected because the solutions:

- offered material reductions in grid import energy at times which coincided with network needs;
- were common technologies well understood by customers;
- introduced no to limited business process implications;
- were served by a well-developed and mature services market;
- offered a relatively short timeline for implementation;
- offered customers an attractive return on investment;
- calculation of savings from implementation relatively straightforward; and
- independent verification pathways via the Clean Energy Regulator and the NSW Energy Savings Scheme.

The selection of preferred market providers was based upon submissions to the EOI and internal analysis of capability. Five different market providers were initially selected with a range of solutions and customer segment expertise. Development, negotiation and execution of contracts with all market providers was challenging with execution of all agreements not completed until about six months later than originally scheduled. The complexity and length of time required to negotiate contracts with individual market providers resulted in an extension to the project.

Phase 2 activities are currently in progress with about 10 months of project activities remaining. Initial results collated up to the end of Sep 2019 indicated that the customer response to the incentives offered was materially lower than anticipated. At this point, market providers had not achieved any uptake for the energy efficient lighting offers; and customer response to the Solar PV offers was limited.

Assessment of feedback from customers via the market providers showed that:

- enthusiasm for investment in Solar PV was much greater than for energy efficient lighting;
- the lead time required for customers to commit to investing in a Solar PV system was longer than anticipated;

Analysis of project results to Sep 2019 identified several issues. In addition to concerns related to the delayed start to the incentive offer period, there were concerns that:

- not all customer segments were being effectively addressed by the selected market providers; and
- the customer mix in selected program area two was insufficient to draw broad trial conclusions.

At this time, the decision was made to make several changes to program operations. These included:

- extending the project duration and customer incentive availability;
- increasing the number of market providers;
- broadening the customer segment capability;
- increasing the geographic area for target area two; and
- increasing the incentive rate for the market provider initially established at a lower rate.

Details on the individual market providers and program areas are detailed on Ausgrid's dedicated project page which can be accessed on our website; see www.ausgrid.com.au/dm

Shortly after onboarding the first of the additional market providers, government restrictions relating to COVID-19 commenced. This caused disruption to the project in two different ways. Firstly, it polarized customers into those who suffered under the restrictions, and those whose business increased, and for 1-2 months the project was disrupted as neither of these two basic customer groups were pursuing or progressing solar or energy efficiency capital works. Secondly the government stimulus program as it related to instant asset write-offs could potentially have played into the decision-making process for the businesses that did proceed. While anecdotal evidence suggests that this was not the case, it is difficult to conclusively rule in or out.

The table below summarises the results of the trial activities to end June 2020. Note that some providers had been operating for a limited time at this point. The results represent valid project activities where implementation was complete, a rebate was claimed by a market provider, reviewed and paid under the project. The total sum of installations in a project area is a key project result upon which to test against the objectives.

Table 14 - Power2U Project Activity Summary (to June 2020)

Provider	Solar PV (kW)	Lighting (MWh)
#1	554	90
#2	0	0
#3	198	176
#4	0	0
#5	0	0
#6	0	0
#7	0	0
Total	**742**	**266**

Qualitative feedback from the market providers did indicate that the incentive had increased the level of interest in the energy efficiency technologies, but the number of installed systems remained low.

An additional element of the project involved the use of a facilitation service and more modest incentive to encourage accelerated take-up of solar PV on schools in the two local government areas. The facilitation service was delivered by a local council with significant experience and success in delivering solar facilitation to schools. The program offers schools advice on what can be installed at their premise, the potential savings from the installation, how to navigate and apply for funding and curriculum content on solar PV for the schools. Results from this element of the trial area detailed in Table 9 below. So far two schools have their solar panels installed, and an additional 8 schools are expecting installation in either Term 3 holidays or Christmas break. In total 24 schools were eligible and approached under the program.

A snapshot of activities is provided in the table below:

Table 15 - School Facilitation Summary

Item	2018-2019	2019-2020	Forecast 2020-2021	Forecast at Completion
Number of schools approached	24	-	-	24
Number of feasibility assessments conducted	17	-	-	17
Number of schools assisted/coordinating funding		13	-	13
Number of schools assisted/coordinating solar installations		4	6	10
Number of acceptances for solar PV installations		3	7	10
Number of schools with installed solar PV		2	8	10
Installed solar capacity (kW)		46	252	298

The results from the school facilitation project stream indicates positive engagement activity to date with 17 of 24 schools accepting the feasibility study offer. Reasons for schools rejecting this offer include issues such as imminent school construction which would preclude the installation of rooftop solar PV. The feasibility assessment investigates the viability of the installation of solar on the school premises and provides a clear recommendation to the school with costs and savings.

A key learning from the activities observed over the past year was the lengthy processes and the range of impacting factors that occurs between the feasibility assessment step and the approval for installation. Once the feasibility assessment is completed, it is presented to the school's P&C Committee who approves for the work to proceed to obtain funding or not. To progress to installation a school must prove to the Department of Education, or equivalent school administrator, it has secured sufficient funding, which will usually be formed from a combination of internal school funds and other funding sources.

The majority of the 17 schools that were assessed applied for grants in the first half of 2019-2020 however outcomes from a key federal grant source was delayed by around 6 months.

Since the grant announcements towards the end of 2019-2020, 10 schools have progressed to the tender and installation phase. Eight of these schools are still waiting for the NSW Dept of Education's tender process to be completed before installation commences. It is anticipated that all 10 schools will complete installation before the final closing date of the program.

The reasons behind the 14 schools that have not pursued solar include being unable to source sufficient funding, physical site issues such as no suitable roof space or heritage constraints, and redevelopment works being planned that would render any installation obsolete.

9.8 Other Information

General information about the Power2U project can be accessed on Ausgrid's Demand Management web page from the Innovation Research and Trials link: www.ausgrid.com.au/dm

If you have a specific information request regarding this project which may assist you in understanding, evaluating or reproducing this project please contact demandmanagement@ausgrid.com.au.

10 Virtual Power Plant (Battery Demand Response)

This project is a continuing Demand Management Innovation Allowance (DMIA) project from Ausgrid's last regulatory control period 2014-2019 into the current 2019-2024 regulatory control period. The following project report provides details of the project activities up until the end of the 2019-2020 regulatory year.

The project will be ongoing into the 2020-2021 regulatory year.

10.1 Project nature and scope

Ausgrid's Battery Demand Response (Virtual Power Plant, VPP) trial explores whether battery VPP's can provide reliable and cost competitive sources of demand reductions or voltage support services to defer network investment. This project seeks to show how the grid can integrate with renewables and partner with industry and customers to maximise grid efficiency benefits and reduce costs for customers. This project aims to investigate the potential application of demand response for residential batteries for network support services by engaging with customers with an existing battery system that is VPP capable.

10.2 Project aims and expectations

The three primary objectives of the project are to:

- Test whether customer battery systems offer a technically and commercially viable demand management option.
- Test customer take-up of a network support (demand response) offer whereby customer battery systems are dispatched to align with network needs.
- Investigate and trial the battery dispatch systems from market providers and explore possible integration of battery management platforms or systems within the Distributed Energy Resource (DER) optimisation platform of Ausgrid's Advanced Distribution Management System (ADMS).

Secondary objectives include;

- Better understanding of the types of customer battery systems being installed by early adopters of the technology
- Better understanding of the impacts on maximum demand and energy volume for a customer with a battery system with and without a demand response offer.

10.3 How and why project complies with the project criteria

This research project explores the demand management capability of a battery VPP (Virtual Power Plant) with market providers. Over the course of the trial, the batteries located on customer's premise are dispatched to provide support to the network. Each Ausgrid dispatch event is crafted to explore a research objective in areas such as the delivered reduction in demand on the grid and the performance of battery management systems. By offering reliable and cost competitive sources of demand reductions or voltage support services, battery VPPs have the potential to help avoid or defer network investment.

Battery VPPs are considered a new and emerging concept and the technology is rapidly evolving. The project is considered innovative in that this is a large scale VPP (multiple MWs of dispatchable capacity) being tested by a distribution network service provider across a range of different battery aggregators, aggregator and customer models and battery manufacturers.

10.4 Implementation approach

The project is planned to be divided into 3 phases to align with the objectives set for the project:

- Phase 1 – Battery customer market research
- Phase 2 – Customer trial over 2 or more years
- Phase 3 – Distributed Energy Resource integration with the Advanced Distributed Management System (ADMS)

Phase 1 of the trial included collation and analysis of information of battery systems connected to Ausgrid's network and an exploration of possible offers and contractual arrangements with a range of different market providers (e.g. battery suppliers, aggregators and energy service providers). This Phase was completed in 2018-2019.

Phase 2 of the project includes customer battery system dispatch and further development of aggregator partnerships. This Phase was initiated in 2018-2019.

Phase 3 of the project will consider integration of network support dispatch and constraint management into the DER platform of Ausgrid's Advanced Distributed Management System (ADMS). This phase has not been initiated and is subject to the availability and capability of provider dispatch platforms and Ausgrid's ADMS.

10.5 Outcome measurement and evaluation approach

The project will be assessed by evaluating the extent to which the project objectives are met as well as meeting the project delivery milestones as outlined in the implementation approach.

Project activities designed to achieve these objectives include:

- establishing dispatch event schedules which test a wide range of battery and VPP performance including summer and winter peak events and periods of minimum demand;
- collaborating with providers to better understand customer views and preferences;
- analysis of battery performance for dispatch and non-dispatch days across a range of scenarios;
- identification of customer benefit from both VPP dispatch and business as usual battery operation;
- assessment of the impact of retail tariffs on customer benefits;
- comparing battery performance across individual battery types and VPP providers;
- assessing for the option of expanding the number of customer and/or the number of VPP providers;
- collaborating with VPP providers to improve dispatch performance and trial innovative battery management techniques to better align battery dispatch performance with network needs; and
- comparing resultant VPP performance and costs, adjusted for any possible future improvements, against representative network needs to determine the viability and cost effectiveness of the solution.

10.6 Costs of the project

The table below shows Ausgrid's actual project costs for 2019-2020, total project expenditure to date and the total expected project costs by the completion of the project.

Table 167 - Project Costs

Budget Item	Actual project costs 2019-2020	Total project costs as at end of June 2020	Total expected project costs
Total project costs (excl GST)	$290,314	$505,473	$1,150,000

10.7 Project Activity and Results

10.7.1 Summary of project activity to date

Ausgrid's partnership with Reposit Power[1] marked the beginning of the customer trials with hundreds of customers combining to form a 1MW (megawatt) VPP. In 2019-2020, Ausgrid completed an open tender

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[1] https://www.repositpower.com

process to add new VPP providers to the trial, which received 11 responses from the market. As part of the process, Evergen[2] and ShineHub[3] were selected to join the trial. Currently there are about 350 battery customers participating in the trial across the three VPP providers.

The project activities have not been planned to align with an area of the network with an investment need. The project is designed to build capability and capacity and explore efficient demand management mechanisms with market providers. This will include measuring the effectiveness and sensitivities of changing incentive levels on encouraging customer demand and gauging how effective they are in achieving permanent demand reductions.

10.7.2 Update on material changes to the project

Due to Covid-19, Ausgrid's interactions with the VPP providers have been restricted to online platforms. Future planned research activities such as customer experience surveys will explore how Covid-19 has impacted the trial customers and their energy usage patterns.

10.7.3 Results

The results from dispatches on a summer day and a winter day are presented on the following pages.

The VPP dispatch profiles are compared against the load profile of a typical 11kV feeder with a forecast capacity constraint to explore the potential of battery VPPs in reducing peak demand. The 11kV feeder is part of Kurri zone substation in the Hunter Region, which supplies 1300 customers and had a forecast capacity constraint of 190kW in 2019-2020. The feeder has 220 solar customers and negligible battery customers[4]. The feeder was part of Ausgrid's Gillieston Heights Demand Management RFP published in 2019, in which Ausgrid invited non-network option providers to propose demand management initiatives to address capacity constraints in the area.

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[2] https://www.evergen.com.au

[3] https://www.shinehub.com.au

[4] There are less than 10 battery customers on the feeder. For the analysis in this report, it will be assumed that currently there are no battery customers on the feeder.

Summer Dispatch Day

On 28 January 2020, Ausgrid scheduled a dispatch with 69 VPP battery customers in the Hunter Region between 16:00-20:00. This was a hot day with temperatures peaking at 39.6°C at Maitland Airport. The customers have an average nameplate battery storage capacity of 9.1kWh/customer and an average maximum discharge capacity of 3kW/customer. Ausgrid did not schedule any manual pre-charging of the battery prior to the dispatch.

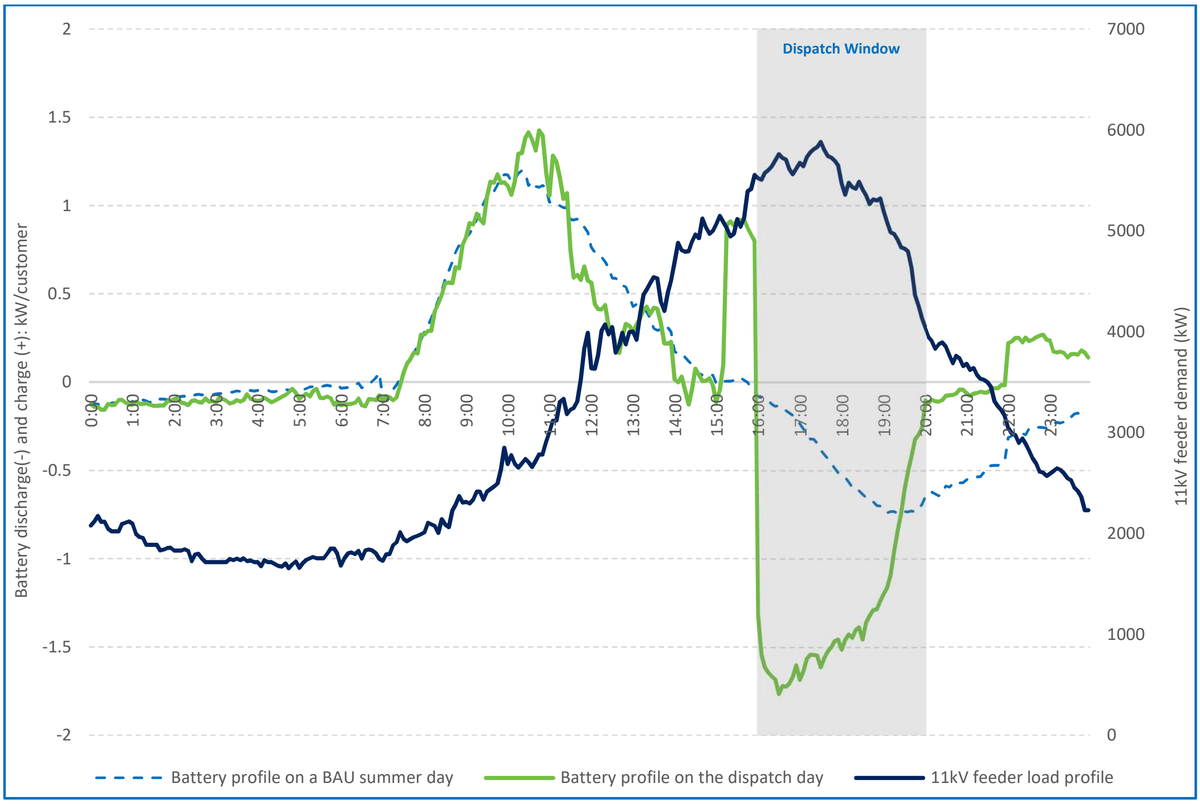
For reference, a BAU (Business-As-Usual) summer peak battery operating profile for the fleet of dispatched batteries is presented in the chart (dashed in light blue). The summer BAU profile is calculated by averaging the profiles of the batteries on hot weekdays (maximum temperature above 30°C) on non-dispatch days during the summer of 2019-2020, excluding public holidays.

The figure below displays the results of a VPP dispatch which coincided with the peak period of the feeder. An average of 5.1kWh/customer of battery energy was delivered during the dispatch window (shaded), compared with the average nameplate battery storage capacity of 9.1kWh/customer.

Due to the dispatch being called 45 minutes prior to the dispatch window, the battery management system had a short amount of time to prepare for the dispatch. The battery management system consequently pre-charged the batteries during the 45 minutes period prior to the dispatch window and created a power 'spike' between 15:15-16:00. This verified the ability of the battery management system to pre-charge at short notice.

The degradation of the dispatch performance over the period of the dispatch event meant that by end of dispatch period, performance was only about 10% of peak dispatch kW.

Figure 20 - VPP dispatch profile compared against load profile of 11kV feeder 80923 at Kurri zone on 28 January 2020



In order to assess the potential of the VPP without the interference of the battery pre-charge, the impact of the battery pre-charge between 15:15-16:00 was removed from the data for 28 January 2020 (refer to Figure 20). This is equivalent to locking out the batteries (no charge or discharge), a feature that is available for the majority of the VPP platforms. No adjustments have been made to the VPP profile within the dispatch window.

Figure 21 - Adjusted VPP profile compared against load profile of 11kV feeder 80923 at Kurri zone on 28 January 2020

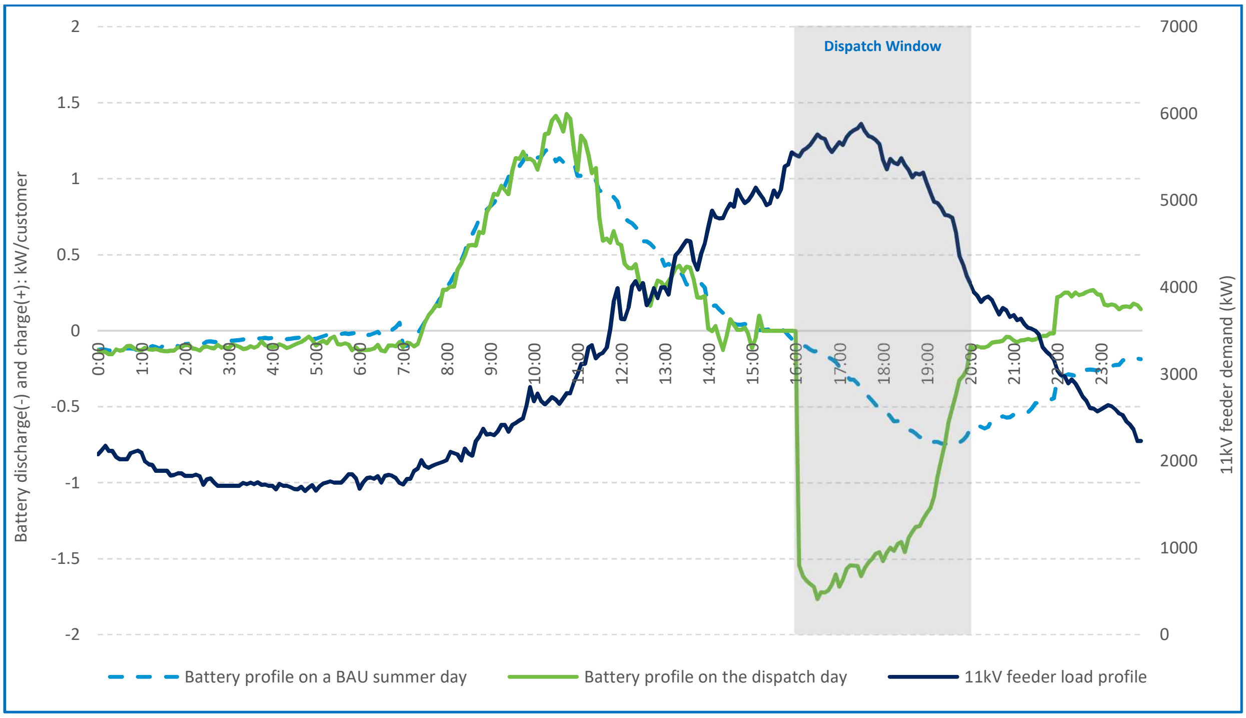


Table 17 below shows the projected peak demand reductions on the representative 11kV feeder with various percentages of battery customers on the feeder, based on the adjusted dispatch profile (not including pre-charge) in Figure 8. There is sufficient demand reduction from the VPP dispatch to address the capacity constraint on the 11kV feeder for 2019-2020 in the modelled scenario where 10% of the feeder customers have a VPP enabled battery.

As can be seen in the table, the improvement from the VPP dispatch in the demand reduction relative to the BAU profile is about 420% at the 5% battery customer level and 330% at the 20% battery customer level.

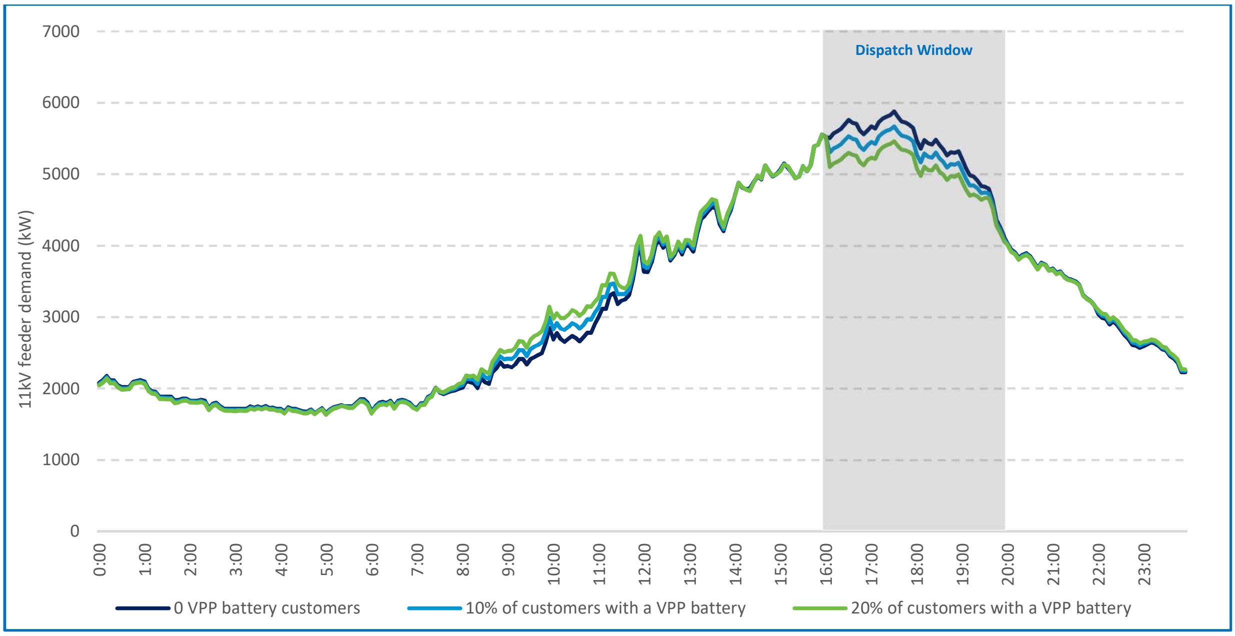
The table also shows that the ‘new’ peak demand for the feeder still occurs within the dispatch window in the scenarios where 5% and 10% of the customers have a VPP enabled battery. The ‘new’ peak demand is outside of the dispatch window at the 20% VPP battery customer level. In this scenario, adjustments to the timing and duration of the dispatch would need to be explored to address the ‘new’ peak demand outside of the dispatch window and to achieve a larger peak demand reduction.

Table 17 - Projected VPP impact on 11kV feeder 80923 at Kurri zone for the dispatch on 28 January 2020

		VPP			**BAU**		
Percentage of customers on the feeder with a battery	**Number of battery customers**	**Max feeder demand across the day (kW)**	**Time**	**Peak reduction across the day (kW)**	**Max feeder demand across the day (kW)**	**Time**	**Peak reduction across the day (kW)**
0 (as is)	0	5881	17:30	0	5881	17:30	0
5%	65	5777	17:30	105	5857	17:30	25
10%	130	5672	17:30	210	5832	17:30	50
20%	260	5555	15:55	327	5782	17:30	99

Figure 22 below presents the projected impact of the adjusted (no pre-charge) dispatch in a scenario where 10% and 20% of the customers on the feeder have a VPP enabled battery equivalent to the average battery size in the Ausgrid trial.

Figure 22 - Projected impact of VPP dispatch on 11kV feeder 80923 at Kurri zone for the dispatch on 28 January 2020



Winter Dispatch Day

On 14 July 2020, Ausgrid scheduled another dispatch with the same 69 VPP battery customers in the Hunter Region between 17:00-20:00. This was a cool day with temperatures dropping to 7.6°C overnight and peaking at 16.5°C during the day at Maitland Airport. The dispatch was called at around 17:00 on 13 July 2020, approximately 24 hours prior to the dispatch window. As noted, these customers have an average nameplate battery storage capacity of 9.1kWh/customer and an average maximum discharge capacity of 3kW/customer.

For reference, a BAU winter peak battery operating profile for the fleet of dispatched batteries is presented in the graph (dashed in light blue). The winter BAU profile is calculated by averaging the profiles of the dispatched batteries on cool weekdays (maximum temperature below 20°C) on non-dispatch days during the winter of 2019, excluding public holidays.

Figure 23 below displays the results of a VPP dispatch which coincided with the peak period of the feeder. On average 5.3kWh/customer of battery energy was discharged during the dispatch window (shaded), compared with the average nameplate battery storage capacity of 9.1kWh/customer.

With the dispatch being called 24 hours prior to the dispatch window, the batteries were able to pre-charge during the off-peak period (12-7am), which avoided the need for any significant pre-charging of the batteries prior to the dispatch window.

The degradation of the dispatch performance over the period of the dispatch event meant that by end of dispatch period, performance was only about 10% of peak dispatch kW.

Figure 23 - VPP profile compared against load profile of 11kV feeder 80923 at Kurri zone on 14 July 2020

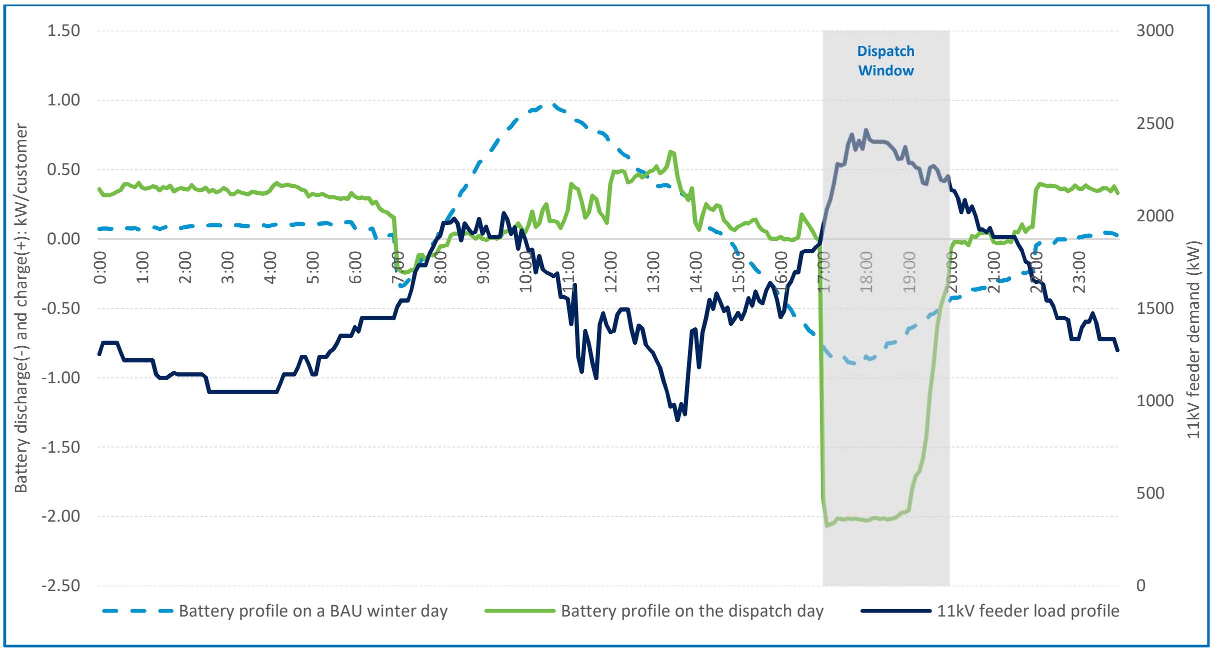


Table 18 below shows the projected peak demand reduction on the representative 11kV feeder with various percentages of battery customers on the feeder, based on the dispatch profile on 14 July 2020. There is sufficient demand reduction from the VPP dispatch to address the capacity constraint on the 11kV feeder for 2019-2020 in the modelled scenario where 10% of the feeder customers have a VPP enabled battery.

As can be seen in the table, the improvement from the VPP dispatch in the demand reduction relative to the BAU profile is about 240% at the 5% battery customer level and about 150% at the 20% battery customer level.

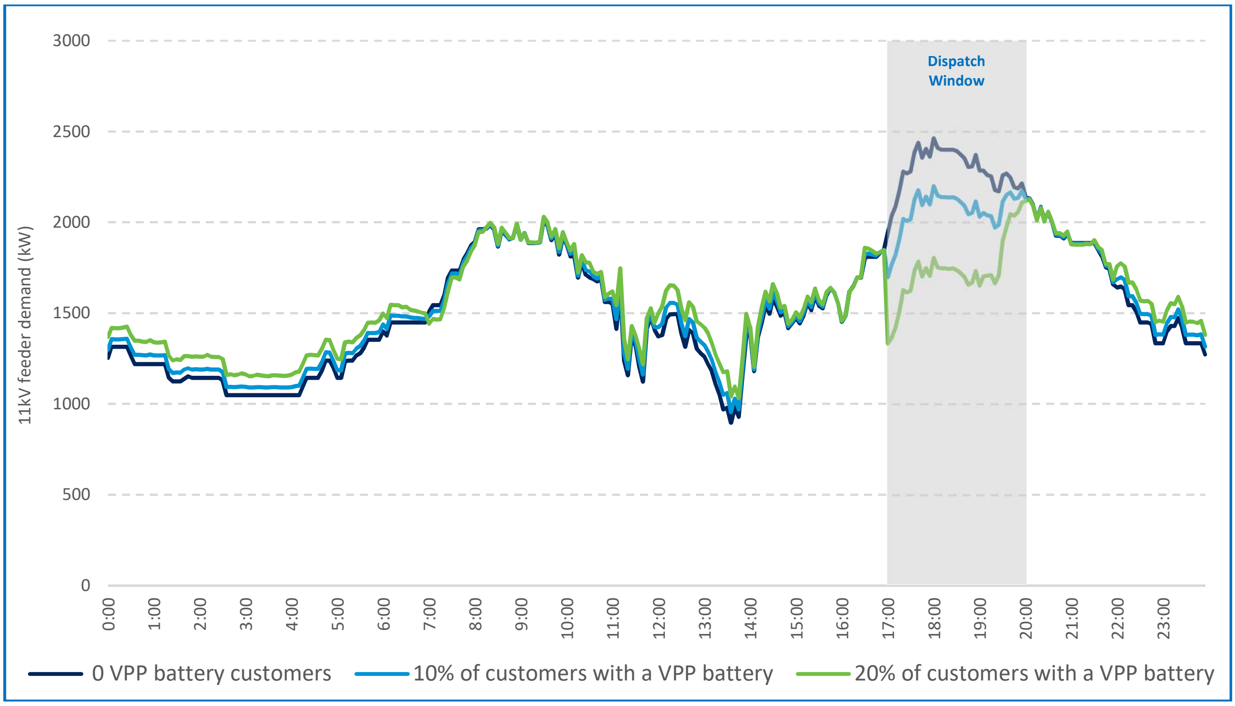
The table also shows that the 'new' peak demand for the feeder still occurs within the dispatch window in the scenarios where 5% and 10% of the customers have a VPP enabled battery. The 'new' peak demand is outside of the dispatch window at the 20% VPP battery customer level. In this scenario, adjustments to the timing and duration of the dispatch would need to be explored to address the 'new' peak demand outside of the dispatch window and to achieve a larger peak demand reduction.

Table 18 - Projected VPP impact on 11kV feeder 80923 at Kurri zone for the dispatch on 14 July 2020

		VPP			**BAU**		
Percentage of customers on the feeder with a battery	**Number of battery customers**	**Max feeder demand across the day (kW)**	**Time**	**Peak reduction across the day (kW)**	**Max feeder demand across the day (kW)**	**Time**	**Peak reduction across the day (kW)**
0 (as is)	0	2465	18:00	0	2465	18:00	0
5%	65	2333	18:00	132	2410	18:00	55
10%	130	2201	18:00	264	2355	18:00	110
20%	260	2127	20:05	338	2246	18:00	219

Figure 24 below shows the projected impact of the dispatch in scenarios where 10% and 20% of the customers on the feeder have a VPP enabled battery equivalent to the average battery size in the Ausgrid trial.

Figure 24 - Projected VPP impact on 11kV feeder 80923 at Kurri zone for the dispatch on 14 July 2020



Discussion

The dispatch results suggest that VPPs have the potential to offer considerable demand reductions on constrained network assets in scenarios where the size of the VPP fleet is sufficient. In addition, the modelled results demonstrate that targeted VPP dispatches produce larger peak demand reductions compared to BAU battery operation. The results also highlight the importance of dispatch timing and managed pre-charging of the battery in optimising VPP dispatches.

10.8 Other Information

An Interim report[5] was released in August 2019 detailing the results of the first stage. A progress report detailing the results to July 2020 is expected to be published in early 2020-2021.

These publications are available from Ausgrid's Demand Management web page from the Innovation Research and Trials link: www.ausgrid.com.au/dm

If you have a specific information request regarding this project to assist in understanding, evaluating or reproducing this project please contact demandmanagement@ausgrid.com.au.

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[5] VPP Interim Report: https://www.ausgrid.com.au/Industry/Demand-Management/Power2U-Progam/Battery-VPP-Trial