Demand Management Innovation Allowance Mechanism

Annual Compliance Report, 2020-2021

September 2021

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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 2020-2021 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 2020-2021 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
Ongoing Projects past 30 June 2021		
Hot Water Load Control	This project was developed to understand the current and future capability of dynamic load control as a demand management solution appropriate for the Ausgrid network and to explore how Ausgrid, retailers and customers can collaborate to optimise operation of the load control system for the benefit of all consumers. This understanding will be built through internal analysis, collaboration with customers and industry and load control field trials. Where necessary the trials will include partnerships with third parties including metering providers and energy retailers.	This project aims to research and develop the capability and capacity for using hot water load control as an effective demand management solution. The project is considered innovative in that it will explore the use of the latest control technology and platforms for controlling hot water systems through a diversity of smart meter types, metering providers and retailers and will engage with a wider range of stakeholders including customers, retailers and metering providers to better understand the multiple values provided by hot water load control to customers and the energy industry. With around 90,000 customers with controlled load devices in the smart meter this puts Ausgrid in a unique position to trial a range of different demand management options in collaboration with customers, retailers, and metering providers.
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. The project 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	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

	or reduce the need for longer term network infrastructure upgrades.	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 and in which Ausgrid is both co-funding and an in-kind contributor in partnership with Energy Consumers Australia and Ausnet Services. The project aims to understand and forecast customers' changing digital lifestyle trends and their impact on future household electricity demand, including at peak times.	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.
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 conduct research to explore customer response, awareness, and interest in the concept to inform the development of a potential trial. Over the course of the trial, the project will support ongoing customer engagement activities to maintain engagement and customer experience related activities.	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.
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, customer models and battery manufacturers.
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.

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 2020-2021 regulatory year on a total of eight ongoing projects with a total of $1,236,401 claimable costs under the DMIAM. The below table provides a project cost summary outlining the amount of the allowance spent during all regulatory years in the regulatory control period 2019-2024 (Section 2.3 (3) (a) and (e) of the AER DMIAM Guidelines):

Project	Project status at end of June 2021	Incurred project costs 2019-2020 (excl GST)	Incurred project costs 2020-2021 (excl GST)
Stand Alone Power Systems	Complete June 2020	$23,291	$0
Hot Water Load Control	Ongoing	$0	$14,296
Peak Time Rebate	Ongoing	$40,786	$193,488
Electric Vehicle Demand Research	Ongoing	$202,134	$33,722
Digital Energy Futures	Ongoing	$174,565	$105,610
Cost Reflective Network Pricing Research	Ongoing	$38,029	$175
Community Battery Feasibility Study and Research	Ongoing	$267,578	$58,670
Power2U (Demand management for replacement needs)	Ongoing	$311,450	$475,029
Battery Demand Response (VPP) Trial	Ongoing	$290,314	$355,410
TOTAL projects		**$1,348,147**	**$1,236,400**

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 Hot Water Load Control

This project is a new Demand Management Innovation Allowance (DMIA) project introduced in the current 2019-2024 regulatory control period. The following project report provides details of the project activities up until the end of the 2020-2021 regulatory year.

The project will be ongoing into the 2021-2022 regulatory year.

3.1 Project nature and scope

This project was developed to understand the current and future capability of dynamic load control as a DM solution appropriate for the Ausgrid network and to explore how Ausgrid, retailers and customers can collaborate to optimise operation of the load control system for the benefit of all consumers. This understanding will be built through internal analysis, collaboration with customers and industry and load control field trials. Where necessary the trials will include partnerships with third parties including metering providers and energy retailers.

Ausgrid currently has around 480,000 customers with controlled load tariffs which predominantly supply electricity to domestic hot water storage systems, although other loads such as electric vehicles, pool pumps and small business appliances can also be connected to these controlled load tariffs. We estimate that on a typical day the thermal energy storage potential in the hot water tanks connected to Ausgrid's controlled load tariff is in the range of 4 to 7 GWh, which is equivalent to around 400,000 to 700,000 household batteries of 10kWh usable electrical storage capacity.

The technology currently used by Ausgrid to control the on and off electricity supply times to appliances connected to the controlled load tariffs is currently mixed. The majority of load control devices in Ausgrid's network still use the traditional "ripple" control system but Ausgrid also uses separate time switches and load control devices within electricity meters.

Since the introduction of the Power of Choice metering reforms in 2017 there has an increase in the number of customers that have their load control device in the smart meter with around 90,000 customers now having a smart meter-based load control device. As smart meters are owned by independent metering providers, the switching times are not directly controlled by Ausgrid but rather specified in the controlled load tariff conditions in *Ausgrid's ES7 Network Pricing Guide*. Metering providers can remotely alter the control schedules of smart meters in a more dynamic manner, which allows a wider range of demand management solutions for off peak hot water systems.

3.2 Project aims and expectations

The primary objective of this project is to explore the optimal operation of controlled load hot water to identify appropriate dynamic operating terms and schedules and the resultant tariff conditions necessary. The project will also seek to understand the efficacy of using hot water load control to better manage local voltage. Additionally, the project will aim to explore the regulatory mechanisms that may assist in effecting optimal operation.

3.3 How and why project complies with the project criteria

This project aims to research and develop the capability and capacity for using hot water load control as an effective demand management solution. The project is considered innovative in that it will explore the use of the latest control technology and platforms for controlling hot water systems through a diversity of smart meter types, metering providers and retailers and will engage with a wider range of stakeholders including customers, retailers and metering providers to better understand the multiple values provided by hot water load control to customers and the energy industry.

3.4 Implementation approach

The project is planned to take place over two to three years from 2021 to 2022/23 as follows:

Phase 1 - Scoping study (data analysis, technology, and market assessments)

The first phase of the project allows for the preparations needed to develop a detailed scope for a second phase of the project. At the end of phase 1 the scope for phase 2 will be reviewed and updated as part of a DMIA implementation proposal. Additionality, there is anticipated to be a Network Innovation component of the project which will be scoped with implementation to be funded from the network innovation program separate to the demand management innovation mechanism funding.

The first phase activities may include;

- Analysis of hot water load control and solar customer information to determine suitable trial locations, including penetration of smart meters, retailers and solar penetration and identification of locations with potential emerging network constraints.
- Technology assessment of smart meter control functionality in the market.
- Market assessment of metering provider and retailer commercial models and arrangements
- Customer research to better understand customer perceptions, understanding and responses to appliance load control and controlled load tariffs in general.

Phase 2 and 3 – Trials

The exact scope of Phase 2 and 3 trials will be developed during Phase 1 with the intention to run customer trials in collaboration with metering providers and retailers.

3.5 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:

- Understanding the potential for using more dynamic control of appliances through the controlled load tariffs as a demand management solution
- Running a series of trials in collaboration with customers, retailers and metering providers that aim to explore the practical implementation of using dynamic control of appliances through the smart meter.

3.6 Costs of the project

The table below shows Ausgrid's actual project costs for 2020-2021, total project expenditure to date and the total expected project costs by the completion of the project.

Table 1 - Project costs

Budget Item	Actual project costs 2020-2021	Total project costs as at end of June 2021	Total expected project costs
Total project costs (excl GST)	$14,296	$14,296	$315,000

3.7 Project Activity and Results

3.7.1 Summary of project activity to date

The project activity up to June 2021 has mainly consisted of conceptual development as well as commencing on the phase 1 data analysis, technology and market assessment activities as outlined in the implementation approach.

3.7.2 Update on material changes to the project

No material changes to the project as this is a new project.

3.7.3 Collected results

There have been no collected results for the project so far.

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 2020-2021 regulatory year.

The project will be an ongoing project into the 2021-2022 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 involves 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 and modification on past retailer trials and will explore PTR customer density and peak event duration and provide insight into network support impacts.

If viable, the approach being trialed 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 having commenced in 2020-2021.

The first phase of this project includes the implementation of collaborative PTR trials with retailers. The initial PTR events have taken place in 2020-2021 and have confirmed the functionality of the basic retailer PTR process, provided insight into the Retailer customer recruitment strategy and customer demand response and satisfaction.

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

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

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, adoption of appliance automation and other viable options identified in stage 1.

Further details for phase 2 will be determined as the trial progresses.

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 2020-2021, 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 2020-2021	Total project costs as at end of June 2021	Total expected project costs
Total project costs (excl GST)	$193,488	$253,361	$1,100,000

4.7 Project Activity and Results

In 2020-2021, Ausgrid agreed to partner with AGL and EnergyAustralia to conduct PTR trials. For the past three years AGL and EnergyAustralia have been developing their PTR capability as part of an ARENA funded demand response program[1]. AGL and EnergyAustralia are two of the largest retailers in Australia and serve a significant share of Ausgrid's customers. By incorporating AGL Peak Energy Rewards[2] and EnergyAustralia's PowerResponse[3] programs in a single DMIA trial, Ausgrid can expand the project learnings and maximise PTR penetration in nominated locations.

Scheduling a PTR event with the retail partners generally involves providing them with a date, time, and target locations one day before or on the day of the event. The retailers then invite their participating customers to participate in the PTR event. The table below summarises for the nominated suburbs the number of total customers, number of customers with smart meters and number of participating customers in the PTR trial. Note that to date there have been no material efforts by Ausgrid or our partners to acquire customers specifically in these areas. The participant numbers to date are wholly due to State-wide or National marketing campaigns established by our Retailer partners.

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[1] https://arena.gov.au/renewable-energy/demand-response/

[2] https://www.agl.com.au/newcampaigns/peakenergyrewards

[3] https://www.energyaustralia.com.au/home/electricity-and-gas/power-response

Table 3 - Customer participation rate by project suburb

Suburb	Total customers	Total smart meter customers	PTR Participants	Percentage of total customers participating in PTR
Aberglasslyn	2366	1092	188	8%
Beecroft	3431	1037	177	5%
Bolwarra	551	241	4	1%
Bolwarra Heights	1178	509	88	7%
Cameron Park	3371	1650	275	8%
Carlingford	1923	383	2	0%
Castle Hill	1279	437	79	6%
Cheltenham	788	235	1	0%
Cherrybrook	6289	2079	329	5%
Chisholm	1565	1025	154	10%
Cliftleigh	862	592	97	11%
Edgeworth	2968	731	115	4%
Fletcher	2624	1411	252	10%
Gillieston Heights	1820	746	112	6%
Hamlyn Terrace	3178	1665	259	8%
Heddon Greta	1082	514	85	8%
Largs	752	272	3	0%
Louth Park	323	184	24	7%
Mindaribba	53	13	1	2%
Rutherford	5627	1874	4	0%
Thornton	4473	1744	317	7%
Wadalba	1551	642	115	7%
Warnervale	424	224	7	2%
Woongarrah	1980	944	141	7%
Total	50458	20244	2829	6%

4.7.1 Summary of project activity and collected results to date

Baselines

PTR performance is determined by comparing a customer's actual energy consumption with a prediction of what would have been used (baseline) if the PTR event had not occurred. There are many different baseline methodologies in use in Australia and overseas and our retail partners use different baseline methodologies for assessing customer performance. EnergyAustralia has adopted the CAISO10[4] methodology developed by the California Independent System Operator for their demand response programs. AGL implements their own process based on historical weather data and loads. The PTR results presented in the tables below (i.e.Table 5, Table 6 and Table 7) were calculated using each respective retailer's baseline methodology.

Ausgrid's internal analysis of aggregate demand from participating customers has used an aggregate level day-matching approach. For example, the analysis of the event day on 25/01/2021 (see Figure 3 and Figure 5), uses a similar weather day on 23/01/2021 as the baseline to estimate the demand reduction from the PTR event.

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[4] https://www.energyaustralia.com.au/sites/default/files/2020-11/201120_PR_Baseline_Calculation_Doc.pdf

Implementing an appropriate baseline for residential customers, particularly at an individual customer level, can be challenging due to highly variable factors such as weather, customer behaviour and solar output. Energy companies are encountering issues such as false negatives where customers that genuinely changed their behaviour are not being recognised by their baseline methodology as having reduced their consumption.

With an increasing number of residential customers having rooftop solar, and a material share of customers with smart meters having solar, calculating an accurate baseline for solar customers is critically important. The report '*Baselining the ARENA-AEMO Demand Response RERT Trial*'[5] , in the review of the baseline methods used for the ARENA-AEMO trial, states that *"none of the baseline approaches that were tested were found to produce good or acceptably accurate baselines for the residential PV segment in any of the simulated events… this result is very much a product of the inability to account for total PV output where net metering is used".*

The need for a robust and standardised baseline methodology which is effective for residential customers will be important in ensuring that demand response continues to develop as an important solution for customers, networks, and retailers.

Event selection

Dispatch events were selected to coincide with days when electricity demand was expected to be high for the local network. As the maximum annual demand for Ausgrid's local network can occur in summer or winter, both summer and winter event days were selected.

Event durations of 2-3 hours were selected as local peak events are typically 2-4 hours in duration. Note that event duration of 3 hours had not been regularly tested by our Retail partners. Shorter duration events are typically sufficient for Retailer requirements and so the extended duration used was a test of customer response over this longer time period.

The table below details the dispatch event date and time and the climate conditions for Cessnock Airport, a weather station nearby to many of the participants.

Table 4 - Dispatch event days and temperature

Date	Time	Retailer partner	Cessnock Max Temperature (°C)	Cessnock Min Temperature (°C)	Note
14/01	17:00 - 20:00	EA	35.6	16.4	
25/01	16:00 - 19:00	EA	37.1	14.0	2nd highest max temp in Jan
26/01	17:00 - 20:00	EA	38.1	16.3	Highest max temp in Jan
10/06	17:00 - 19:00	EA	8.8	5.7	Lowest max temp in Jun
22/01	14:00 - 16:00	AGL	34.5	12.4	
25/01	16:00 - 19:00	AGL	37.1	14.0	2nd highest max temp in Jan
12/02	17:00 - 19:00	AGL	33.4	12.8	Highest max temp in Feb
1/03	16:30 - 18:30	AGL	32.5	18.7	2nd highest max temp Mar
9/06	17:30 - 19:30	AGL	13.2	7.3	
10/06	17:30 - 19:30	AGL	8.8	5.7	Lowest max temp in Jun
6/07	17:30 - 19:30	AGL	16.3	-1.7	Lowest min temp in Jul
9/07	17:00 - 20:00	AGL	13.7	5.1	Lowest max temp in Jul

[5] https://arena.gov.au/assets/2019/09/baselining-arena-aemo-demand-response-rert-trial.pdf

Customer response for PTR events with EnergyAustralia

EnergyAustralia's Power Response program was introduced in 2017 as part of a demand response initiative supported by ARENA, AEMO and the NSW Government.[6] Following the end of this initiative, EnergyAustralia continued the program including an expansion to a number of new participating customers.

All EnergyAustralia customers with a smart meter are eligible to participate[7], with about 49,000 EnergyAustralia customers enrolled in the program in Ausgrid's service area.

PTR event notification process for EnergyAustralia was as follows:

1. Pre-event SMS sent on the day of the event, prior to the event. The aim is to send this message at least 2 hours before the event.
2. Event start SMS a few minutes before the event.
3. Event end SMS at the conclusion of the event.

The customers were asked to respond with an opt-out message to exclude themselves from the event. The customers were rewarded based on their energy reduction ($/kWh). As shown in Figure 1 below, the response rate for the customers were relatively consistent across all events.

Figure 1: Percentage of EnergyAustralia customers that participated (didn't opt-out) in PTR events with EnergyAustralia in 2021

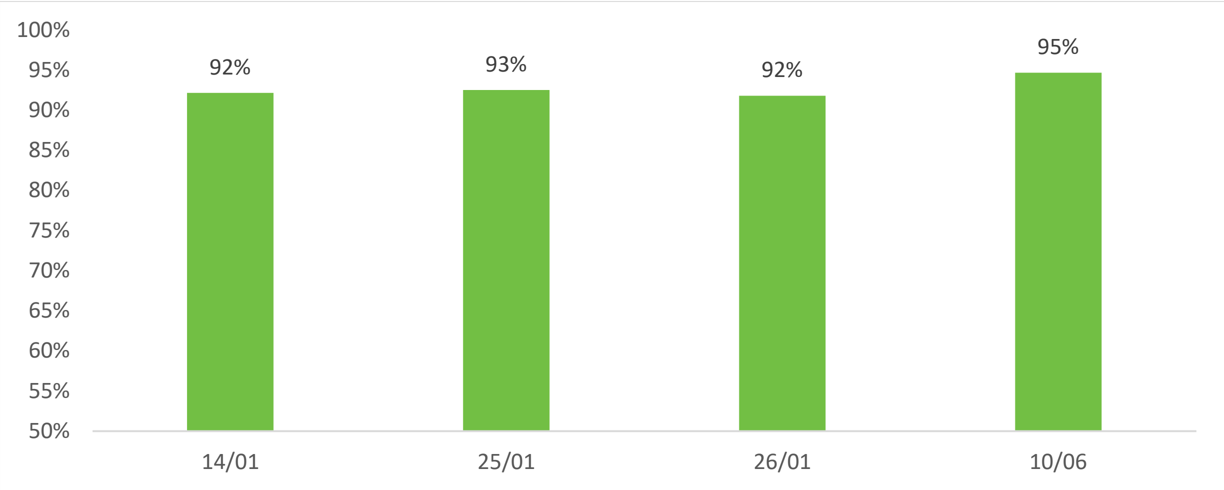


Table 5 shows that the average energy reduction for participants fluctuated across the events and were relatively small for some events. This suggests that there were a significant number of non-performing participants.

6 https://arena.gov.au/projects/energyaustralia-demand-response-program/

7 excepting exclusions such as life support customers.

Table 5 - PTR results for EnergyAustralia customers that participated (didn't opt-out) using EnergyAustralia's baseline

Event date	Time	Number of enrolled customers invited to participate	Number of enrolled customers who did not opt out (Participants)	Average reduction for participants (kWh/customer)[8]
14/01	17:00 - 20:00	2340	2157	-1.22
25/01	16:00 - 19:00	2345	2170	0.42
26/01	17:00 - 20:00	2339	2148	0.11
10/06	17:00 - 19:00	2257	2137	1.41
Average		**2320**	**2153**	**0.18**

Due to the blending of active and inactive customers, the results in Table 5 tell us little about the response from those customers who are actively engaged in the program. To address this, we have attempted to isolate active customers by defining active customers as those who reduce their consumption by at least 5%. Note that this does assume that the baseline methodology is an accurate representation of customer energy use in the absence of the dispatch event.

Table 6 below summarises an estimate of the energy reduction for participating customers, as defined above where about half of the customers not opting out were found to reduce their energy use by at least 5% compared to the EnergyAustralia baseline. This analysis shows that when non-performing customers are excluded, the identified energy reduction is significant. This highlights the importance of differentiating interested and uninterested customers when assessing PTR results of participants recruited via an opt-out method.

Table 6 - PTR results for EnergyAustralia customers that did not opt-out and achieved 5% minimum reduction using EnergyAustralia's baseline

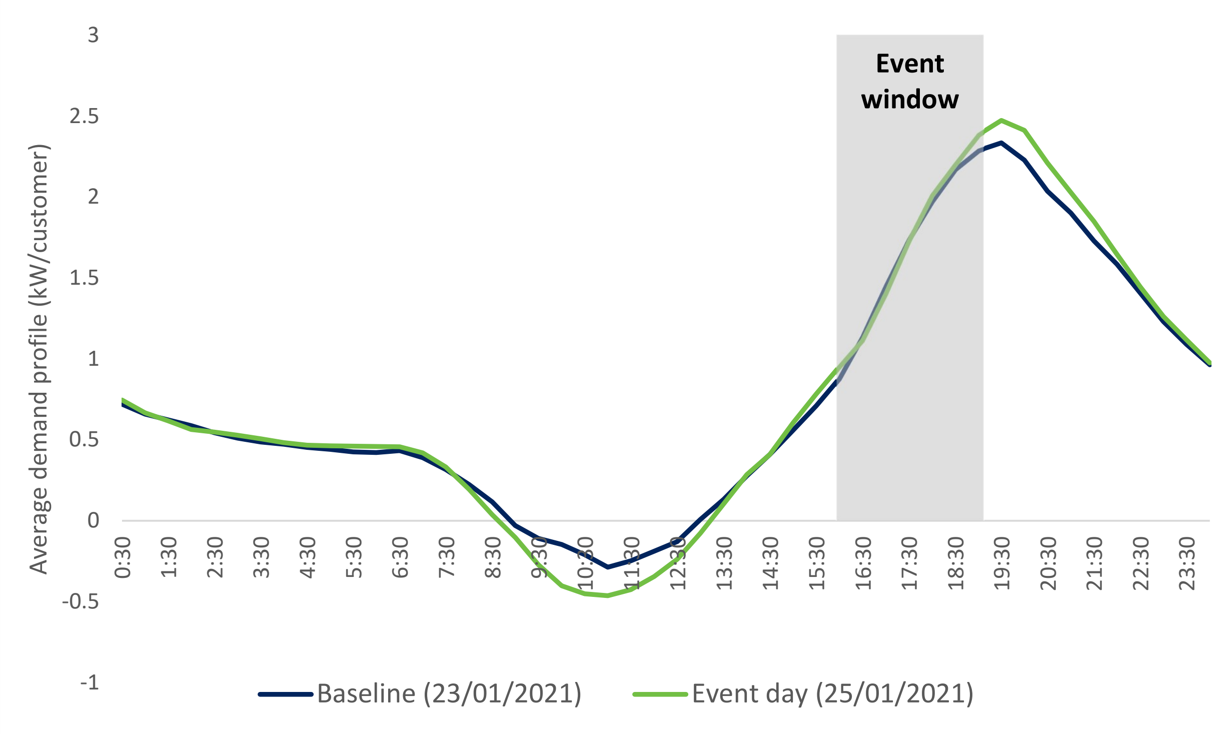
Event date	Time	Number of enrolled customers invited to participate	Number of customers who did not opt out and with at least 5% reduction	Average reduction for customers who did not opt out and with minimum 5% reduction (kWh/customer)
14/01	17:00 - 20:00	2340	894	2.71
25/01	16:00 - 19:00	2345	1144	3.44
26/01	17:00 - 20:00	2339	1035	3.70
10/06	17:00 - 19:00	2257	1404	3.12
Average		**2320**	**1119**	**3.24**

As part of Ausgrid's assessment of the customer demand reduction, we used a day-matching approach for an aggregation of all participating customers with the matching day selected on the basis of similar climate conditions. As the bulk of household energy use is associated with heating and cooling, it is changes in temperature that are the primary driver of changing energy use in the home. This approach ignores the variability that occurs from household to household by assuming that these variations average out when assessed in a large enough population.

For the event day on 25/01/2021, which was a peak demand day with a maximum temperature of 37.1°C at Cessnock airport, a baseline day of 23/01/2021 which had a maximum temperature of 36.0°C, was selected. Figure 2 below shows the average demand profile for all EnergyAustralia PTR participants who did not opt out.

[8] A positive number represents energy usage reduction while negative number represents increase in energy usage.

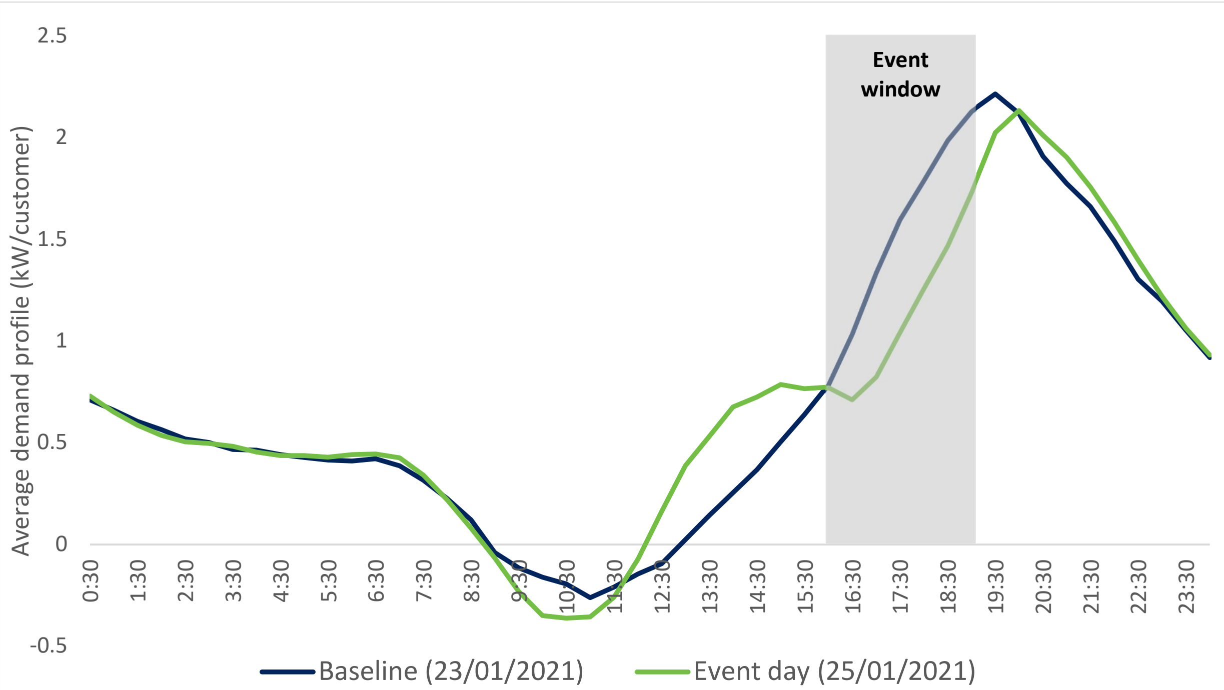
Figure 2 - Demand profile for EnergyAustralia participants (didn't opt-out) in the PTR event on 25/01/2021 compared to Ausgrid's baseline day of 23/01/2021



Similar to Table 5 results above, due to the blending of active and inactive customers the results in Figure 2 tell us little about the demand response from those customers who are actively engaged in the program. To address this, we have similarly attempted to isolate active customers by defining active customers as those who reduce their consumption by at least 5%.

Figure 3 represents the average demand profile for all EnergyAustralia PTR participants who did not opt out and who achieved a minimum demand reduction of 5%. This shows a demand reduction response at the start of the PTR event at around 4pm and of about 0.5 kW across the event time period.

Figure 3 – Demand profile for EnergyAustralia's participants who did not opt out and achieved minimum 5% reduction for event on 25/01/2021, compared to Ausgrid's baseline day of 23/01/2021



Regarding the comparison of the demand profile for the event and baseline day, the energy demand is very similar throughout the morning and late evening hours. The variation from 9:30am to 3:30pm is potentially due to a variation in solar power generation from customers across the two comparison days. Further analysis will be undertaken to explore this difference.

Figure 2 further highlight that participants recruited via an opt-out process include a mix of performing and non-performing customers and so it is important to differentiate them when analysing the results.

Note that the estimated average demand reduction of 0.5kW when using the day matching methodology is lower than the average reduction of 1.1kW per hour as recorded by the Retailer using their baseline methodology. Further analysis is required to explore the accuracy of each methodology.

Customer response for PTR events with AGL

AGL's Peak Energy Rewards program was introduced in 2017 as part of a demand response initiative supported by ARENA, AEMO and the NSW Government[9]. Following the end of this initiative, AGL continued the program including an expansion to the number of participating customers.

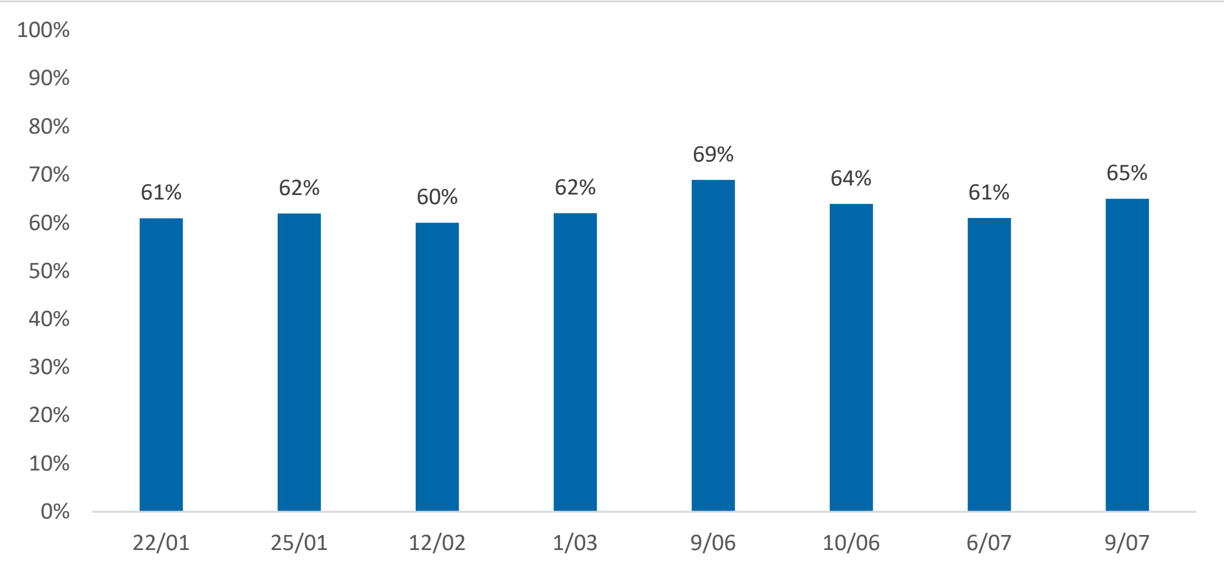
AGL customers with a smart meter are eligible to participate, with about 8,000 AGL customers enrolled in the program in Ausgrid's service area. At present, the program is closed to new participants but with plans to expand the program in future.

PTR event notification process for AGL was as follows:

1. Pre-event SMS sent one day before the event if possible.
2. A reminder SMS on the day of the event.
3. Event start SMS at the beginning of the event.
4. Event end SMS at the conclusion of the event.

The customers are required to respond with an opt-in message to participate in the event. The participants were rewarded based on achieving reduction targets (e.g. 5% reduction from their baseline). Similar to EnergyAustralia, Figure 4 below shows that the response rate for the customers were relatively consistent across all events.

Figure 4 - Percentage of AGL customers that participated (opt-in) in the PTR events with AGL in 2021



[9] https://arena.gov.au/projects/agl-demand-response/

According to Table 7, the results show a considerable energy reduction across all summer events with an average response of 3.2 kWh/event for the four summer event days. For the four winter event days, a lower reduction was measured with an average response of 1.6 kWh/event.

Table 7 - PTR results for AGL customers that participated (opt-in) using AGL's baseline

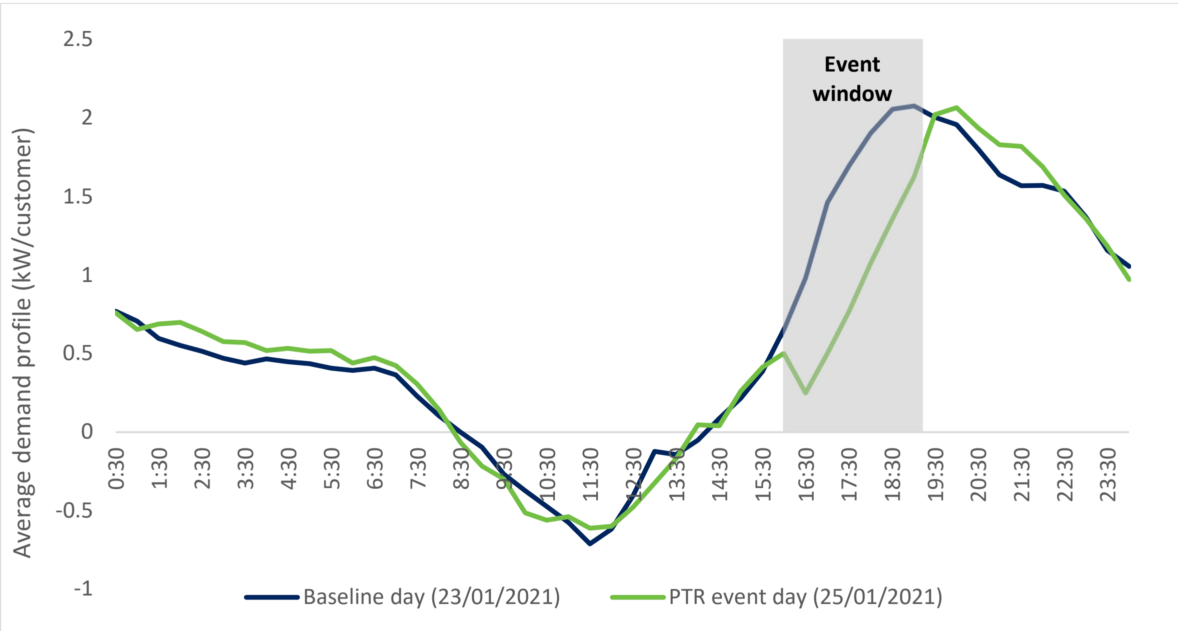
Date	Time	Total number of enrolled customers invited to participate	Participants	Average reduction for participants (kWh/customer)
22/01	14:00 - 16:00	328	200	3.2
25/01	16:00 - 19:00	326	202	3.3
12/02	17:00 - 19:00	333	200	3.4
1/03	16:30 - 18:30	329	204	2.9
9/06	17:30 - 19:30	319	220	2.4
10/06	17:30 - 19:30	319	204	2.1
6/07	17:30 - 19:30	313	191	0.8
9/07	17:00 - 20:00	320	208	1.0
Average		**323**	**204**	**2.4**

Similar to the analysis of the EnergyAustralia customers, as part of Ausgrid's assessment of the customer repsonse, we used a day matching approach for an aggregation of all participating AGL customers with the matching day selected on the basis of similar climate conditions. As with the EnergyAustralia customer cohort, an event day on 25/01/2021 has been compared with a baseline day of 23/01/2021.

Figure 5 below shows that for the AGL customers, the comparison of the demand profile for the event and the day matching baseline indicates a good alignment across all hours outside of the event hours of 4pm to 7pm. At the event start time of 4pm, there is a clear variation from the baseline trend which is then maintained until the event stop time of 7pm. This comparison indicates that the PTR event resulted in an average demand reduction of about 0.8 kW across the event time period for all participating customers.

Note that the estimated average demand reduction of 0.8kW when using the day matching methodology is slightly lower than the average reduction of 1.1kW per hour as recorded by the Retailer using their baseline methodology. Further analysis is required to explore the accuracy of each methodology.

Figure 5 - Demand profile for AGL participants (opt-in) in the PTR event on 25/01/2021



Potential network demand reduction using PTR

With approximately 1600 customers, Telarah zone substation feeder 48010 was identified in 2019 as having a forecast capacity constraint (see Table 8). This feeder was part of Ausgrid's Gillieston Heights Demand Management RFP (Request for Proposal) published in 2019, in which Ausgrid invited non-network option providers to propose demand management initiatives to address capacity constraints in the area. This capacity constraint will be used as a reference network need to assess PTR performance.

Table 8 - Telarah feeder 48010 forecast capacity constraint as stated in Gillieston Heights Demand Management Request for Proposal

	2020/2021	2021/2022	2022/2023	2023/2024
Capacity Constraints (kW)	381	914	1448	1981

Figure 6 shows the load profile for Telarah feeder 48010 on 25/01/2021. To assess the potential demand reduction that could be achieved by PTR, the average participant's reduction on 25/01/2021 (see Figure 3 and Figure 5) is projected on to the demand profile of the feeder. Various PTR participation rates for the feeder customers are projected to determine the potential peak demand reduction. Figure 7 and Figure 8 show the potential PTR impact for these possible future scenarios.

Figure 6 - Demand profile for Telarah zone substation feeder 48010 on 25/01/2021

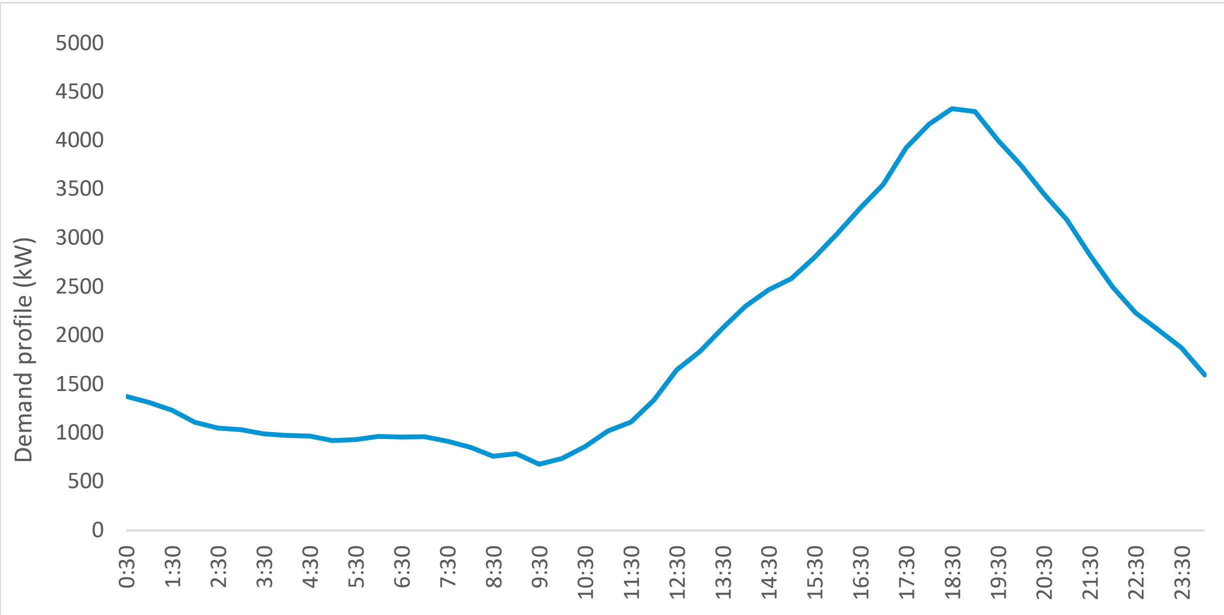


Figure 7 - Projected demand reduction on feeder 48010 based on the PTR event with EnergyAustralia on 25/01/2021

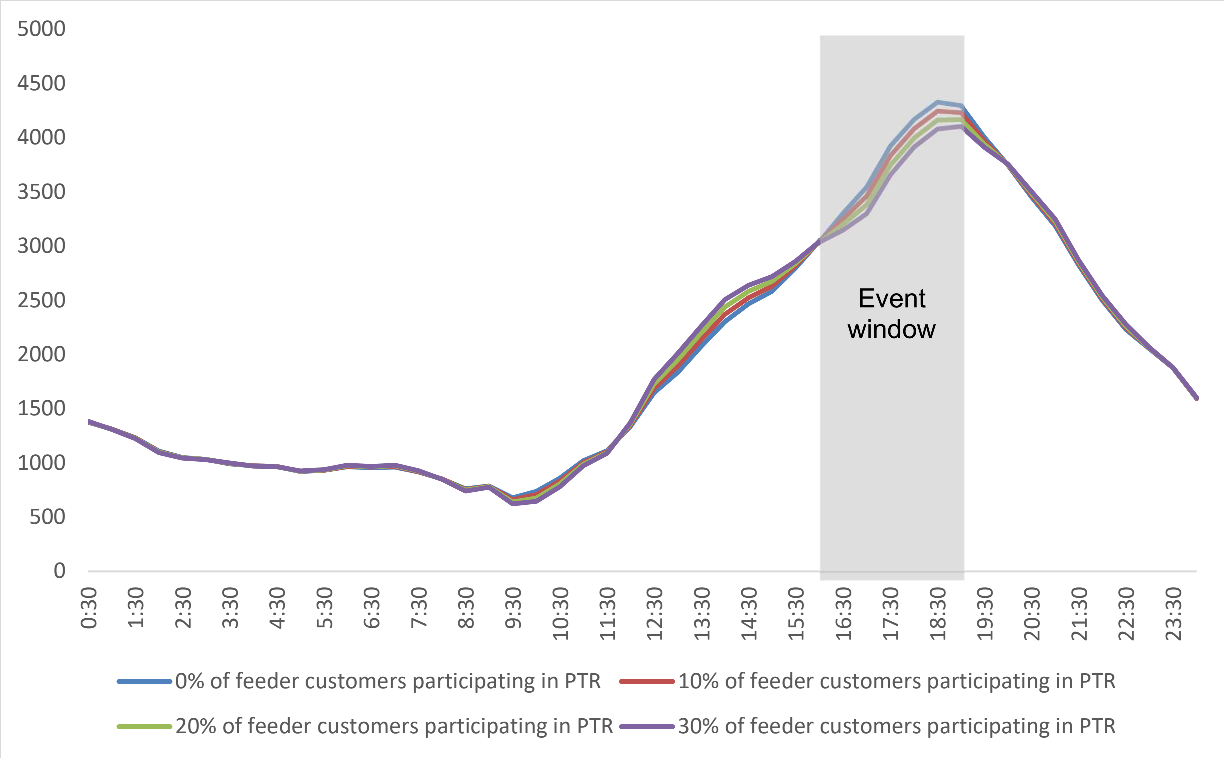
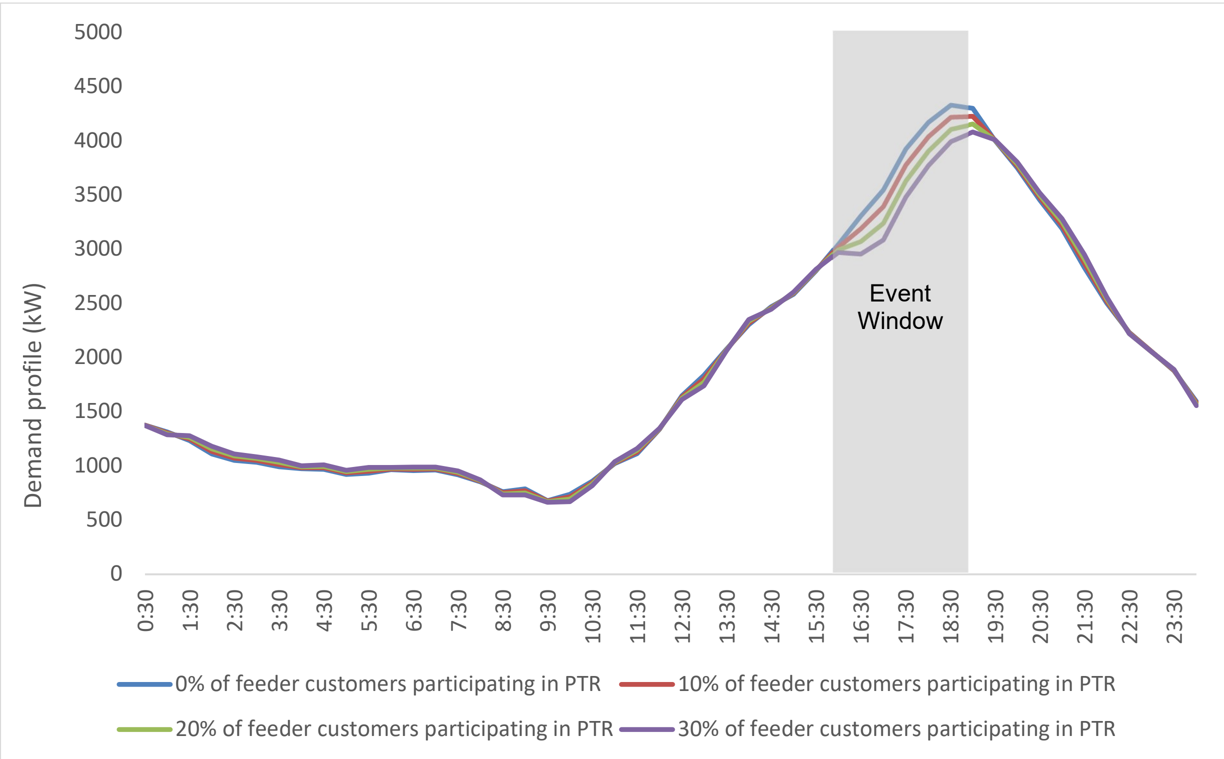


Figure 8 - Projected demand reduction on feeder 48010 based on the PTR event with AGL on 25/01/2021



The PTR event on 25/01/2021 was between 4-7pm, which didn’t align with the entire peak period of the Telarah feeder (see Figure 7 and Figure 8). Figure 9 and

Figure 10 below show the potential demand reduction if there was a similar customer response and the event window had been moved to 5-8pm to align with the feeder peak demand period. These charts highlight the importance of aligning the PTR event window with the asset peak period to maximise the effectiveness of the delivered peak demand reduction.

Figure 9 - Projected demand reduction on feeder 48010 based on EnergyAustralia PTR event on 25/01/2021 with an adjusted event window

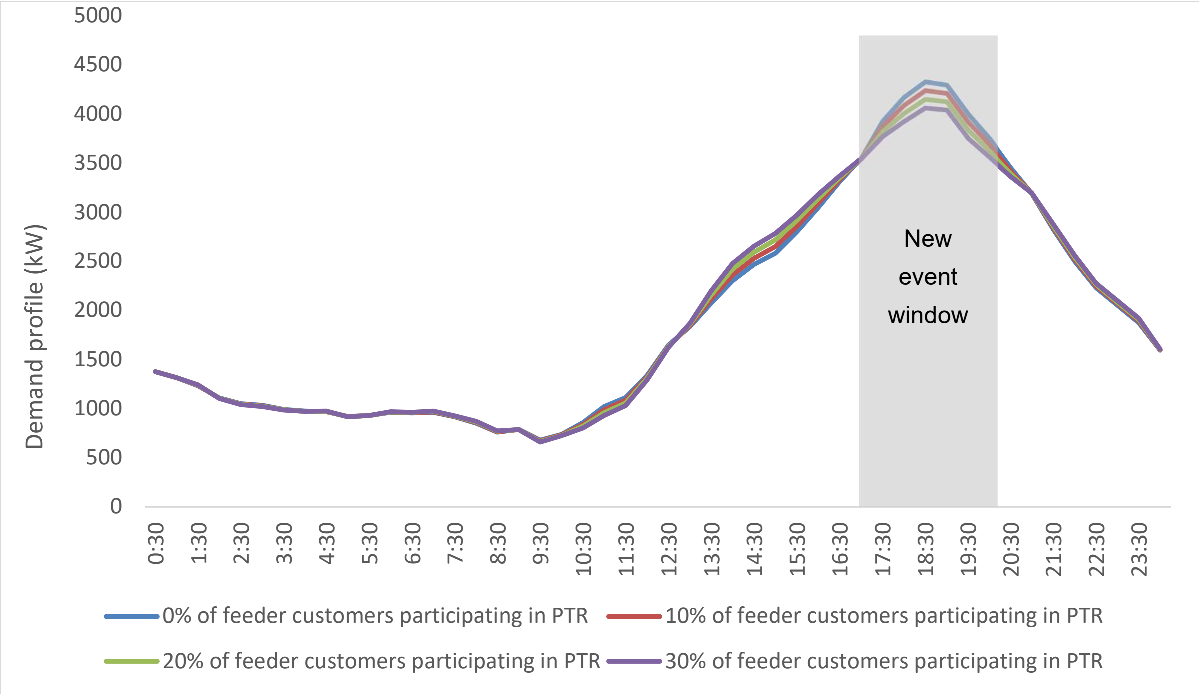


Figure 10 - Projected demand reduction on feeder 48010 based on AGL PTR event on 25/01/2021 with an adjusted event window

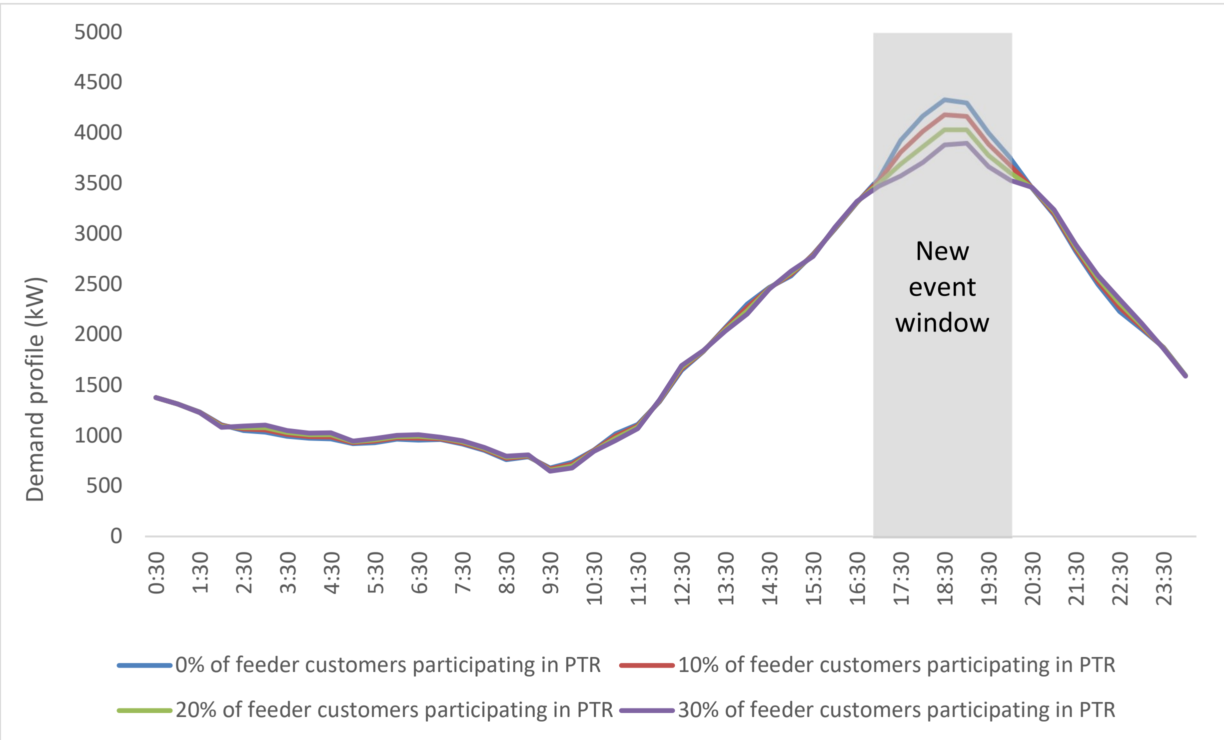


Table 9 and Table 10 below illustrate the potential demand reduction for the feeder based on the estimated average PTR participant response on 25/01/2021. These results show that if 30% of the customers on the feeder had actively participated in the PTR event, the demand reduction may have been enough to largely address the forecast capacity constraint on the feeder for 2020-2021. Approximately 36% of the feeder customers have a smart meter that allows them to participate. In order to have 30% of the feeder customers actively participate at this time, the majority (more than 80%) of the smart meter customers on the feeder would need to be active participants, which is higher than the active participation rate that has been observed in the trial to date.

Table 9 - Projected peak demand reduction for feeder 48010 based on EnergyAustralia PTR event on 25/01/2021 with a shifted event window

Active PTR participation for feeder customers	Number of active PTR participants	Max feeder demand (kW)	Peak demand reduction (kW)
0%	0	4328	0
10%	160	4240	89
20%	320	4151	178
30%	480	4062	266

Table 10 - Projected peak demand reduction for feeder 48010 based on AGL PTR event on 25/01/2021 with a shifted event window

Active PTR participation for feeder customers	Number of active PTR participants	Max feeder demand (kW)	Peak demand reduction (kW)
0%	0	4328	0
10%	160	4180	148
20%	320	4032	297
30%	480	3898	430

Interim survey results

Customer awareness, preferences and satisfaction levels are critical to the ongoing viability of this type of customer flex solution and our Retail partners regularly track customer sentiment. The results of a participant's survey conducted by EnergyAustralia following the January 2021 events are presented below as an example of the customer response received to date.

Figure 11 - Survey results question 1

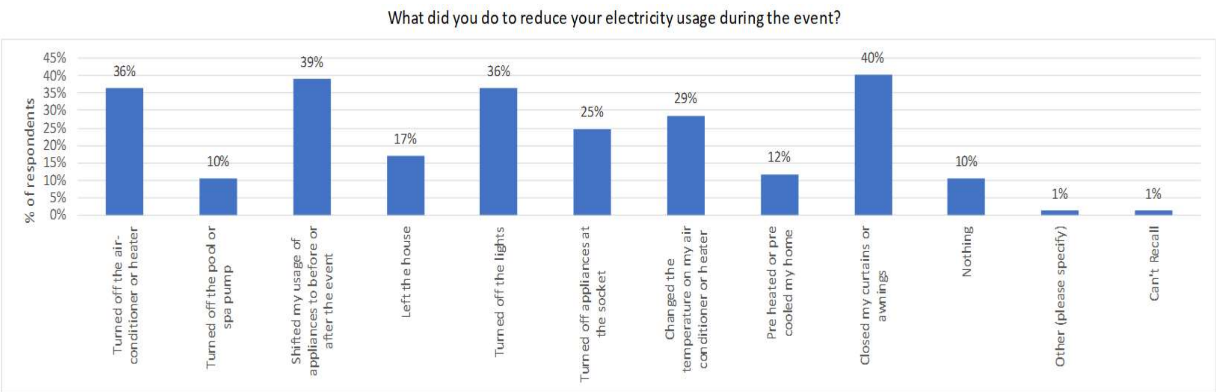


Figure 12 - Survey results question 2

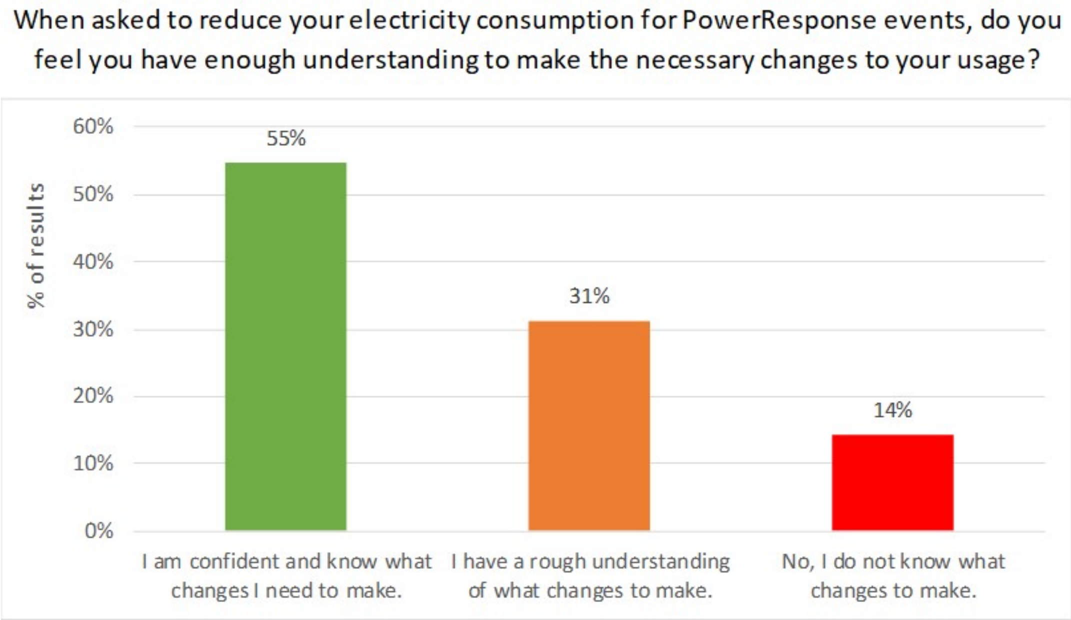


Figure 13 - Survey results question 3

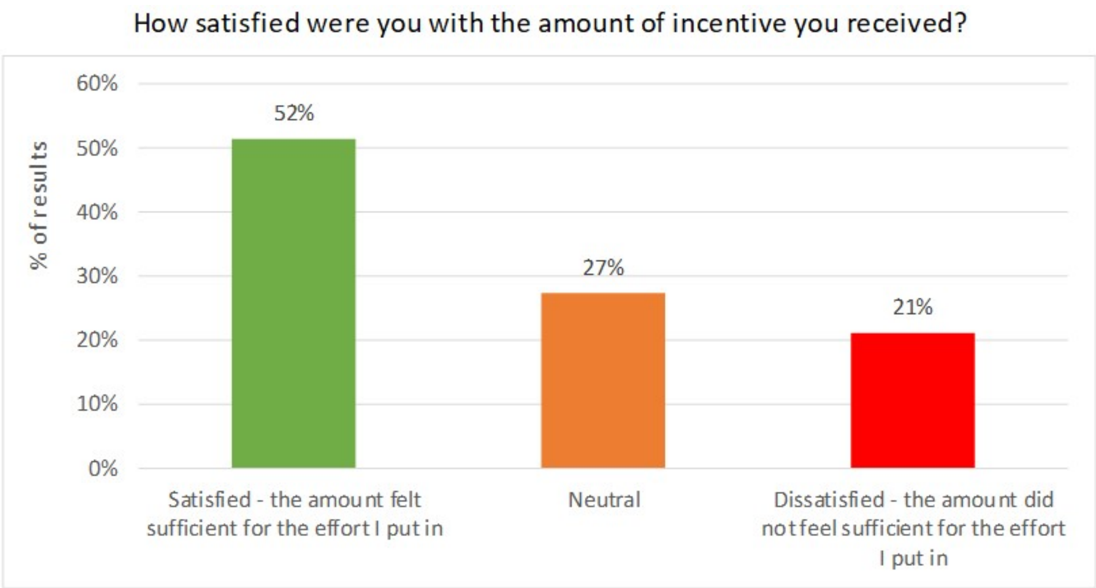


Figure 14 - Survey results question 4

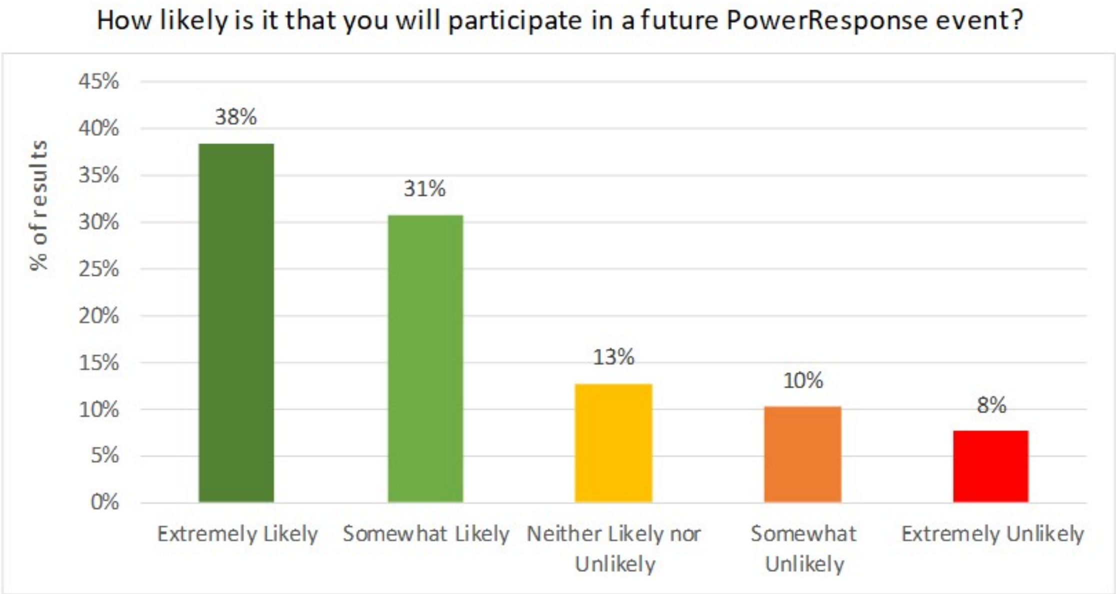


Figure 15 - Survey results question 5

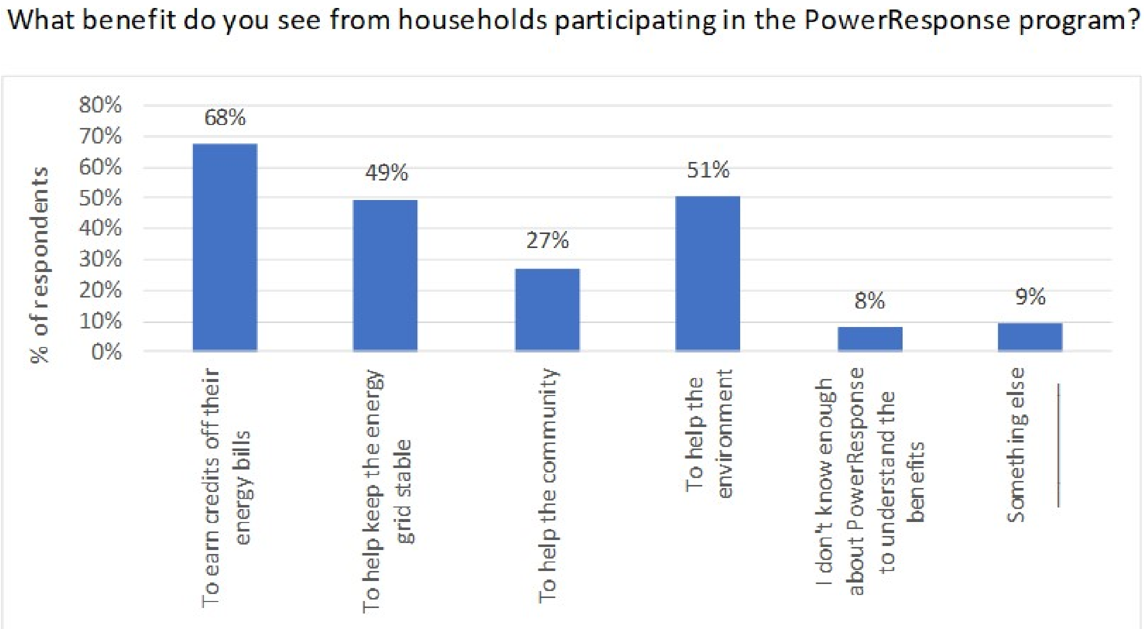
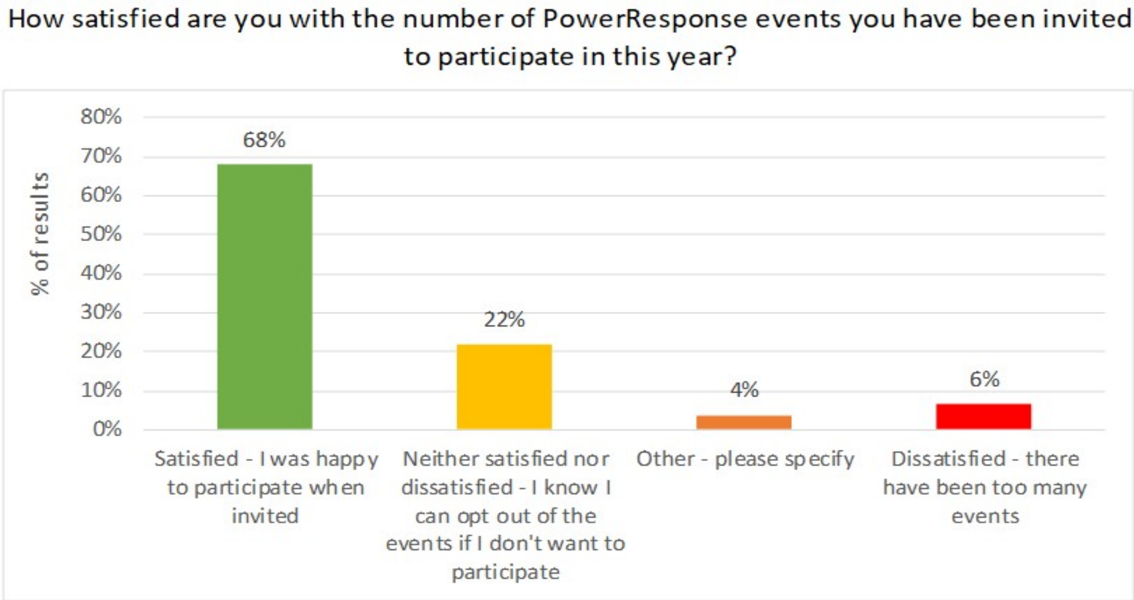


Figure 16 - Survey results question 6



Summary

Key findings from the results to date include:

- Customers' response to the invite SMS was relatively stable across both summer and winter dispatch events.
- While the opt-out method of customer recruitment resulted in higher apparent participation rates, there were a significant number of non-performing customers within the group. When analysing participants recruited via an opt-out method, it's important to differentiate the participating and non-participating customers.
- Energy reduction performance was relatively stable across the 2-3-hour dispatch period indicating customer acceptance for the longer duration events ideal for network needs.
- Stable dispatch performance across a range of high temperature summer days indicates customer willingness and ability to deliver energy reductions on peak demand days.
- Using a day matching methodology, estimated demand reductions were about 0.5 to 0.8 kW. This is lower than the estimate derived by the Retailers using individual customer baselines. Further work and analysis are required to improve the calculation of energy and demand reductions.
- Aligning the PTR event window and the asset's peak demand period is key to optimising the peak energy reduction for the need.
- The need for a robust and standardised baseline methodology which is effective for residential customers will be important in ensuring that demand response continues to develop as an important solution for customers, networks, and retailers.

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 2020-2021 regulatory year.

The project will be ongoing into the 2021-2022 regulatory year.

5.1 Project nature and scope

The forecast uptake of electric vehicles in Australia is still highly uncertain and the most recent scenario forecasts from the Australian Electricity Market Operator (AEMO) were released in the 2021 ISP Inputs and assumptions workbook. The AEMO estimates that in the NEM (all states except WA and NT) there will be a potential increase from around 20,000 EVs in June 2021 to around 2.2 million by June 2031 in the *Steady Progress* and *Net Zero 2050* scenarios and as high as 3.1 million electric vehicles in 2031 in the *Step 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 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 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.

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.

Other innovative aspects of the project will be explored with electricity retailer partners during Phase 2. This will involve exploring the orchestration value of electric vehicle charging for network support services as well as trialling vehicle-to-grid technology for network support services.

5.4 Implementation approach

The project will be conducted in two phases:

<u>Phase 1 - Charge Together project support, led by EVenergi (ARENA-funded)</u>

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.

<u>Phase 2 – Electric vehicle charging trials, EV network tariffs and EV industry engagement</u>

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 2020-2021, 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 11 - Project Costs

Budget Item	Actual project costs 2020-2021	Total project costs as at end of June 2021	Total expected project costs
Total project costs (excl GST)	$33,722	$335,100	$495,000

5.7 Project Activity and Results

5.7.1 Summary of project activity to date

Phase 1 activities were mostly completed during 2019-2020 with the publishing of the final results of the NSW EV owners survey happening during 2020-2021. In addition, the outcomes from the development of the typology based electric vehicle charging planning tool was also published as a case study during 2020-2021.

During 2020-21, the following Phase 2 activities also commenced or were completed

- Participation as a project partner in the ARENA-funded electric vehicle charging trial being led by Origin Energy. Further information can be found under 'Projects' on Arena's website[10]
- Participation in the technical reference group along with other network companies in the ARENA-funded electric vehicle charging trial being led by AGL. Further information can be found under 'Projects' on Arena's website[11]
- Completion of the electric vehicle network pricing consultancy by HoustonKemp outlining recommendations for electric vehicle tariffs

5.7.2 Update on material changes to the project

There were no material changes to the planned activities during 2020-2021 with results from Phase 1 activities being published and Phase 2 activities commencing or being completed.

5.7.3 Collected results

Phase 1: Electric Vehicle Owners Survey – Final Results

The final results for the electric vehicle owners online survey was released publicly during 2020-2021 and can be found on Ausgrid's website in the Demand Management Innovation and Research section at https://www.ausgrid.com.au/dm. An example of some of the key results from the survey contained in the public report are shown below.

[10] https://arena.gov.au/projects/origin-energy-electric-vehicles-smart-charging-trial/

[11] https://arena.gov.au/projects/agl-electric-vehicle-orchestration-trial/

Key Results

Respondent Demographics
- Couples (without children) households (33%) or Couples with children (50%) made up the majority
- Full-time workers or part-time workers (72%)
- 78% live in detached house and 88% owned their home
- Tertiary educated – Bachelor degree or higher (78%)
- Higher than average household income bracket (75%)
- Around a third of respondents were from the Northern Sydney suburbs

Vehicle Ownership
- Less than 12 months old (68%)
- 1 other car in household (53%), 2 or more other cars (32%)
- Tesla most popular brand (78%)

Vehicle Usage
- 10,000-20,000 km/year (56%)
- Many regular trips start between 7 to 10 am (55%)
- The main purposes for regular trips were work, recreation and regular shopping (69%)
- The main purposes for occasional trips were recreation, holiday or visiting family/ friends (75%)
- 58% of regular trip distances were less than 20km compared to 19% for occasional trips

Home Charging
- Vast majority charge at home (83%)
- 10pm-7am was the most popular time for home charging (65%)
- Majority already do (18%) or would consider (58%) using a solar power system to charge their EV
- Decision on when to charge is based on 'when most convenient' irrespective of state of battery charge (37%)

Public Charging
- When using public EV chargers most do so for free (72%)
- The most used public charger locations were shopping centres
- Fast chargers were nearly always used for less than 60 mins

Electricity Pricing
- Above average awareness and knowledge about pricing options
- Around half were on an off-peak tariff for charging their EV, costing them around half as much as a single rate tariff on average
- 56% indicated they used timer setting controls to charge their EV

Demand Management
- 78% would consider participating in demand management (DM) programs for their EV charging
- 51% considered up to $10 per event to participate in a DM program would be worthwhile
- Above average awareness of energy saving actions

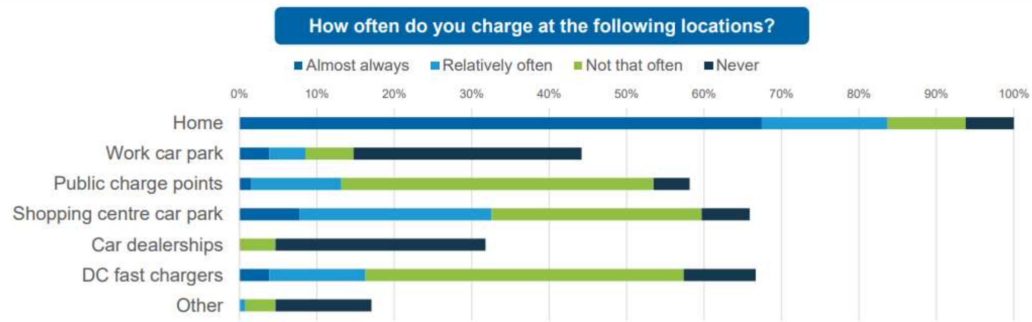
Ausgrid
Connecting communities, empowering lives

Total of 129 owners of NSW registered electric vehicles responded to the survey

2

Charging Location and Charging Frequency

What we wanted to know and why	Results
Understanding how often EV owners charge at different locations is a significant indicator of where the electric vehicle charging may occur and guide solution design.	• 83% charge at home almost always (67%) or relatively often (16%) • Shopping centre car parks were used by around 60% and were the next most common to be used often (33%) • Public charge points and DC fast chargers were used by around 50% to 60% but not used that often (10 to 20%) • Work car parks were only used by 15% of respondents



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(n = 129, all respondents who own a registered electric vehicle in NSW/ACT)

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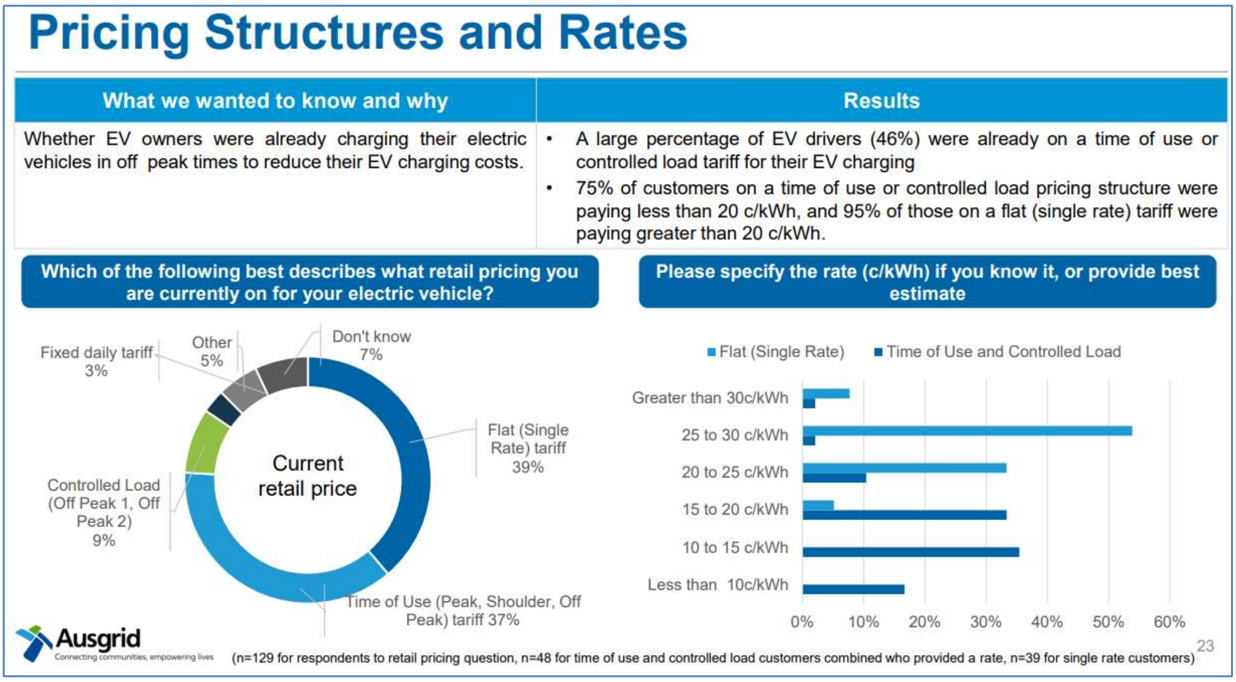
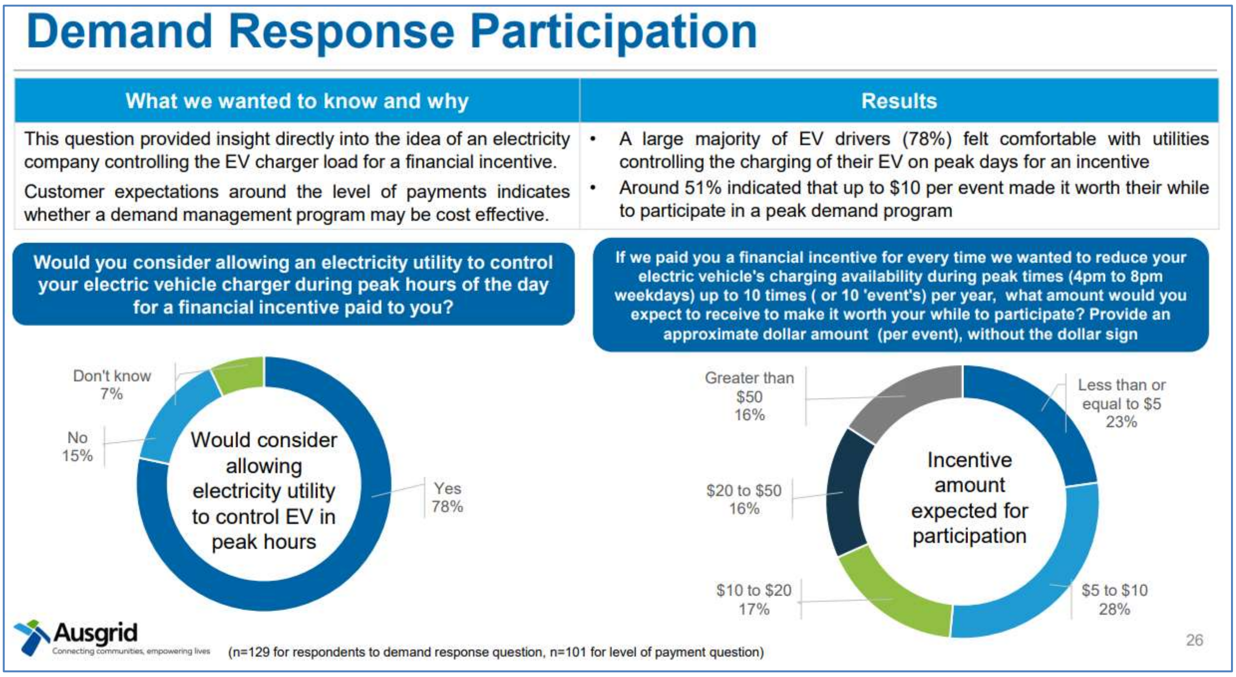




Phase 1: Electric vehicle demand planning tool

As reported in the 2019-2020 annual report a local spatial allocation model was developed to estimate the electrical demand for EV charging using five electric vehicle typologies.

As an outcome of this work, the lead organization on the research project, EVenergi, launched a product called GridFleet. An Ausgrid case study was published as part of this report[12].

[12] https://www.evenergi.com/wp-content/uploads/2021/07/Whitepaper-GridFleet-AUS.pdf

One of the key outcomes from this component of the project was a greater understanding of how the electrification of the transport sector will create new electricity demand in different locations of the network with materially different characteristics. Electric vehicle charging at workplaces, shopping centres and DC fast charging stations will be quite different in nature to residential home charging for example due to variations in customer types, electric vehicle driving patterns, charging capacity requirements and electricity pricing structures. The spatial location of these EV charging typologies will be a key determining factor in the need for investments in the distribution network as a result of this additional electrical load, with each typology requiring different levels of engagement with customers and the industry to develop cost-effective demand management solutions that can be used to shift demand.

Phase 2: Electric vehicle network pricing study

The economic consultant, HoustonKemp, was engaged to provide guidance on the network pricing options that could be explored for electric vehicle charging in future activities. The principal opportunity arising from the uptake of EVs, from a network perspective, is the ability to control or co-ordinate large and flexible loads, thereby minimising the effect on network costs and, at the same time, avoid any loss in amenity for customers with an EV.

The report had two key recommendations with respect to network tariffs;

- to investigate the potential for opt-in locational pricing for stand-alone electric vehicle charge points to encourage better utilization of existing asset capacity and where the incremental network costs are relatively small in a particular location.
- for residential customers, to explore an adapted controlled load tariff to provide improved amenity for electric vehicle owners through options such allowing customers to over-ride the electricity shut-off period for a number of days each year.

The outcomes from this consultancy will be used to inform the strategy and development of efficient network tariffs for electric vehicle charging. Effective network tariffs may have the potential to be used as a cost-effective demand management solution for particular applications and this is planned to be explored further by Ausgrid.

Phase 2: Origin smart charging trial (ARENA-funded)

Ausgrid is a project partner in the Origin EV Smart Charging Trial and Origin published their ARENA Interim Report in June 2021[13]. As at June 2021, Origin had installed 103 smart EV chargers (70 residential and 33 business) to collect a meaningful set of baseline charging data.

Ausgrid has been actively involved in providing feedback and advice to Origin from the perspective of a distribution network company. This has included providing advice about the design of the customer trials with the aim that the managed charging of electric vehicles at the local distribution network level is considered in the trial design. Understanding the electrical demand of unmanaged and managed EV charging combined with an understanding of the potential penetration of electric vehicle chargers in a particular location will assist Ausgrid in understanding what demand management solutions might be most cost-effective in the future.

Phase 2: AGL electric vehicle orchestration trial (ARENA-funded)

Ausgrid is one of seven network companies on a technical reference group to the AGL EV Orchestration Trial and AGL published a Lessons Learnt Report in May 2021[14]. As at May 2021, AGL had signed up 82 participants with 28 chargers installed.

Participation in the technical reference group includes helping design the test program for assessing distribution network impacts and orchestration value. The first technical reference group meeting was held in March 2021 and involved providing feedback to AGL on test cases that could be built into the aggregation software development.

Ausgrid is particularly interested in understanding how unmanaged and managed charging of electric vehicles may affect localized electrical demand with the aim of better understanding the value of EV orchestration as a cost-effective demand management solution. The AGL trial will also involve the installation of vehicle-to-grid chargers and V2G network integration aspects are planned to be explored as part of the project.

[13] https://arena.gov.au/assets/2021/06/origin-ev-smart-charging-trial-interim-report.pdf

[14] https://arena.gov.au/assets/2021/05/agl-electric-vehicle-orchestration-trial-lessons-learnt-report-1.pdf

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 2020-2021 regulatory year.

The project will be ongoing into the 2021-2022 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 2020-2021, total project expenditure to date and the total expected project costs by the completion of the project.

Table 12 - Project Costs

Budget Item	Actual project costs 2020-2021	Total project costs as at end of June 2021	Total expected project costs
Total project costs (excl GST)	$105,610	$293,217	$410,000

6.7 Project Activity and Results

6.7.1 Summary of Project Activity to Date

<u>Stage 1 (completed): Digital and energy futures analysis</u>

Monash University completed the digital and energy futures analysis which was reported in the 2019-2020 annual report.

<u>Stage 2 (completed): Digital ethnography with households</u>

The recruitment survey for the stage 2 ethnographic fieldwork was conducted in March 2020 and reported in the 2019-2020 annual report.

During 2020-2021, the ethnographic fieldwork was conducted by the Monash University research team and the results were recently published. Ausgrid provided input, review, and feedback to the Monash research team around the results from the qualitative research.

<u>Stage 3 (completed): Survey supplement for ECA's annual Energy Consumer Sentiments Survey</u>

The changes to the Energy Consumers Australia Sentiment survey was completed during 2020-2021 and the results are expected to be available in 2021-2022. Ausgrid was involved in providing input, review and feedback to the research team and project partners in the development of the new content and questions.

Stage 4 to 6 (in progress):

Development of the research and activities associated with Stages 4, 5 and 6 commenced in 2020-2021 with the fieldwork for Stage 4 is planned to occur during 2021-2022.

6.7.2 Update on material changes on the project

The Stage 2 qualitative research was delayed due to the impacts of the COVID-19 pandemic in 2020 and the research techniques used were adapted to go online rather than face to face. All virtual interviews were conducted successfully during the 2020-2021 period.

The Stage 4 customer workshops are planned to occur during 2021-2022 and appropriate customer research methodologies are still being finalised.

6.7.3 Collected Results

The reports published so far as part of this project can be found on Monash University's website[15].

Results from the Stage 1 desktop research review project were published in June 2020 and can be found at the link above in the report entitled *Digital Energy Futures: Review of industry trends, visions, and scenarios for the home.*

Results from the Stage 2 digital ethnography involving detailed interviews with 72 households was published in July 2021 and can be found at the link below in the report entitled *Digital Energy Futures: Future Home Life*.

Some of the key findings of both reports are brought together and compared in the executive summary of the *Future Home Life* report where the industry predictions and visions from Stage 1 are compared to the research findings from the detailed customer interviews from Stage 2. One of the key results so far, is that the customer research does not strongly support the industry visions and predictions in many cases. This will need further consideration by the energy industry in terms of how to best design demand management solutions and engage with customers to increase participation in programs that aim to manage electricity demand.

Of note, was that the industry visions of smart appliances and energy management systems enabling automation and more efficient management of energy and reduced peak demand was not well supported by the customer research. Consumers appeared to have limited interest in technology for energy management and many participants expressed preferences for manual control over automation when it came to appliances like heating/ cooling systems. The main appeal of digital technologies to consumers was about increasing pleasure and entertainment in the home rather than opportunities for energy management.

On the two following pages of this report, are excerpts from the Executive Summary of the *Future Home Life* report (pages 7 and 8) which show these comparisons in more detail across the seven household practice domains identified as part of the research. The traffic lights indicate where the research results varied from the energy industry vision. In particular, plans for an automated future using smart controls may be hampered by customer preferences for manual control and limited interest in technology for energy management.

[15] https://www.monash.edu/emerging-tech-research-lab/research/research-themes/energy-futures/digital-energy-futures/reports-and-publications

Comparing Industry Visions to Household Research

Stop: Does not correspond **Proceed with caution:** Somewhat corresponds **Go:** Corresponds

Practice domain	Industry prediction	Finding supported by research	
Charging and Mobility	Technology will enable management of EV charging and match it to the needs of the energy sector.	The industry vision of charging electric vehicles during daylight hours at work was seen as infeasible by most participants, but increased working from home presents an opportunity for daytime charging of EVs during the solar peak.	
	Technology will increasingly automate EV charging decision making for consumers.	Some EV owners had charging settings automated into the car, others had developed manual workarounds to override the car's automated charging function to better fit their existing routines.	
Cooking and Eating	Smart appliances will proliferate and improve the convenience of everyday routines.	Many smart cooking appliances fail to deliver substantial benefits for consumers.	
Healthy Indoor Air and Thermal Comfort	Smart home technologies will manage heating and cooling to deliver savings for both consumers and the energy industry.	Most participants maintain manual control over heating and cooling because they prefer only intermittent use 'when they need it'. The smart functionality in many existing smart technologies, such as air purifiers, are not set to respond to energy pricing but to air quality monitors.	
Living and Play	Broad adoption of smart home technologies is 'just around the corner', bringing improved efficiencies, convenience, and immersive household entertainment. Digital voice assistants will become the hub of the smart home and enable greater household automation.	Households had a wide range of digital devices, but many of these technologies do not live up to industry predictions, such as digital voice assistants, which were mostly used for minor entertainment or simple requests, rather than household automation.	
	Smart appliances will enable better energy management through automated and remote control.	The main appeal of digital technologies was about increasing pleasure and entertainment in the home, not the opportunities it provided for energy management.	
Working and Studying at Home	New technologies, such as improved telecommunications, virtual reality (VR) and augmented reality (AR), will enable studying and working from home in more industries.	The COVID-19 pandemic was accelerating industry predictions of a working from home future, and many desire a hybrid work model. The experience of working from home was less positive for those with smaller spaces and without the financial means to upgrade home spaces or invest in technology. VR was primarily used in gaming, but some suspected VR and AR to be used in future remote work.	

Caring for the Home and its Occupants	Smart home technologies will enable older people to be cared for at home through health and safety monitoring technologies and robotic caring.	Participants were willing to explore technology to support ageing at home and were open to incorporating technology that had clear health and safety benefits. However, many found the automated alerts on existing monitoring systems too frequent to handle everyday life circumstances.	
	Emerging technologies are rarely mentioned as playing a role in caring for children but are causing concerns about children's excessive screen time.	There was hesitancy towards children's use of technology, but a number of devices were often balanced with strict usage limitations, such as tablets that were routinely used in children's care.	
Making, Saving, Storing and Shifting Energy	Better data and automation will enable more efficient management of energy, reduced peak demand, and reduced energy costs for consumers.	Consumers have limited interest in technology for energy management, and enthusiasm for digital technologies is likely to increase energy demand. Very few participants showed long term engagement with their energy data and did not change their practices despite awareness of high energy usage. Many participants expressed preferences for manual control over automation.	
	Consumers are primarily motivated by financial incentives and time-of-use tariffs enable price signals and will encourage load shifting.	Energy saving was driven by a much more diverse set of motivations than price, including educational opportunities, desires to share energy with others in the community, and aspirations towards self-sufficiency. Time-of-use tariffs alone are unlikely to encourage significant load shifting.	

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 2020-2021 regulatory year.

The project will be ongoing into the 2021-2022 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. In July 2018, Ausgrid introduced a seasonal time of use network tariff for residential customers and 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.

As at June 2021, there were approximately 340,000 residential customers on a seasonal time of use network tariff and 110,000 residential customers on a monthly demand network tariff.

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:

<u>Phase 1 – Customer research and surveying</u>

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 2020-2021, total project expenditure to date and the total expected project costs by the completion of the project.

Table 13- Project Costs

Budget Item	Actual project costs 2020-2021	Total project costs as at end of June 2020	Total expected project costs
Total project costs (excl GST)	$175	$96,875	$250,000

7.7 Project Activity and Results

7.7.1 Summary of project activity to date

The phase 1 survey responses collected in June 2019 were provided to Ausgrid during the 2019-2020 period with collected results reported in the 2019-2020 annual report. 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 results were presented in the 2019-2020 annual report.

During 2020-2021 there was no material project activity as outlined in section 7.7.2.

7.7.2 Update on material changes to the project

This project was put on hold for the duration of 2020-2021 due to the reasons outlined in the 2019-2020 annual report which were 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 (which has now reached 110,000 residential customers on demand tariffs as at June 2021);

- 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)

During 2021-2022 it is planned to conduct further customer research including re-surveying customers with a particular focus on understanding why the customer response to the introduction of cost-reflective network pricing remains low with an estimated peak period reduction of around 2% to 5%.. This could be a result of a range of factors including the retail pricing plan structure that customers are exposed to as well as other behavioural factors.

7.7.3 Collected results

Phase 1 customer research

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).

Although preliminary analysis of the survey data was completed further Phase 1 activities were paused during the 2019-2020 year to focus on the demand reduction study.

The project was further paused during 2020-2021 for the reasons outlined in section 7.7.2, but further customer research activities are planned to resume in 2021-2022 to better understand why the customer response to cost-reflective network tariffs is as low as 2% to 5% as quantified in the demand reduction study and analysis.

Phase 2 demand reduction study

The results of the quantitative analysis of the customer response to cost reflective network pricing was reported in the 2019-2020 annual report. The results from this preliminary study estimated that the peak demand reduction in the summer peak period for customers that changed from a flat network tariff to a time of use network tariff 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.

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 2020-2021 regulatory year.

The project will be ongoing into the 2021-2022 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. Additional storage capacity also 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, a customer survey to gauge customer response and attitudes towards the concept and the customer engagement components of the Phase 3 community battery pilot.

8.2 Project aims and expectations

The first phase of the project aimed 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 aimed 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 has now informed the development of a practical trial for the concept in phase three. As part of Phase 3, the DMIA project will explore customer response, perceptions and behaviours as part of the community battery pilot.

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 included the following aspects:

- measure consumer needs, motivations and perceptions to store excess solar power 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, system owners in terms of demographics, household composition and socio-economic factors; and
- ascertain interest levels in future community battery 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 2 and internal and external review of these outcomes. During 2020-2021, 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 has been developed in collaboration with Ausgrid's Network Innovation Advisory Committee (NIAC)[16]. 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 phase two customer research and were supportive of Ausgrid progressing with a community battery pilot.

This DMIA project will continue to fund the customer research and the ongoing customer engagement components of the 2-year customer trial which is part of the 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.

[16] https://www.ausgrid.com.au/About-Us/Innovation/NIAC

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 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 Phase 3 community battery pilot funded under the Ausgrid Network Innovation program. Customer engagement and research elements of Phase 3 will continue under the DMIA project.

8.6 Costs of the project

The table below shows Ausgrid's actual project costs for 2020-2021, total project expenditure to date and the total expected project costs by the completion of the project.

Table 14 - Project Costs

Budget Item	Actual project costs 2020-2021	Total project costs as at end of June 2021	Total expected project costs
Total project costs (excl GST)	$58,670	$485,225	$800,000

8.7 Project Activity and Results

8.7.1 Summary of Project Activity to Date

Phase 1 – Feasibility study and model business case

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. The study assessed a range of technical, commercial, and regulatory issues and concluded the community battery project initiative could be feasible within as little as 3-5 years. The feasibility report can be downloaded from the community battery project page on Ausgrid's website[17].

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 a market research company and input from stakeholders. The survey was completed

[17] https://www.ausgrid.com.au/In-your-community/Community-Batteries/Project-research

at the end of July 2020 and analysis of the results and reporting was completed by the market research company commissioned to conduct the survey by November 2020.

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.

A summary of the key results is provided below in 8.7.3.

8.7.2 Update on material changes on the project

The delivery of the Phase 3 community battery pilot was largely transferred to the Network Innovation program, in collaboration with Ausgrid's Network Innovation Advisory Committee (NIAC). The NIAC was put in place to give customers a role in driving our innovation investment program guided by an underlying set of innovation principles and their terms of reference[18].

As the project moved into Phase 3 during 2020-2021, there was a material change to the project where a DMIA funded component was scoped to support the customer engagement elements of the trial. This includes activities such as customer engagement communication activities, payment services to customers, ongoing maintenance and support for the customer trial app and other activities relating to the customer experience.

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. For reported results from the feasibility study, refer to Ausgrid's DMIA Annual Report 2019-20[19]. Ausgrid's Community battery feasibility report can be downloaded from the project research page on Ausgrid's website[20].

Phase 2 – Online Customer Survey

The survey was conducted in July 2020 with just over 900 Ausgrid customers who had solar PV systems or home batteries connected to Ausgrid's network or who were considering installing a solar system within the next two years. The questions in the survey focussed on measuring customers' existing level of knowledge about community batteries and their sentiment, motivation, and barriers towards the concept of taking part in a community battery trial if presented with the opportunity. In addition, profiles of both solar customers and home battery owners were undertaken and presented in the report.

A detailed analysis of the results was completed and finalised by November 2020. The survey report found that while existing awareness of community batteries was low, when provided with a basic description of the concept, there was a high level of interest and likelihood to sign up to a community battery if they were given the opportunity.

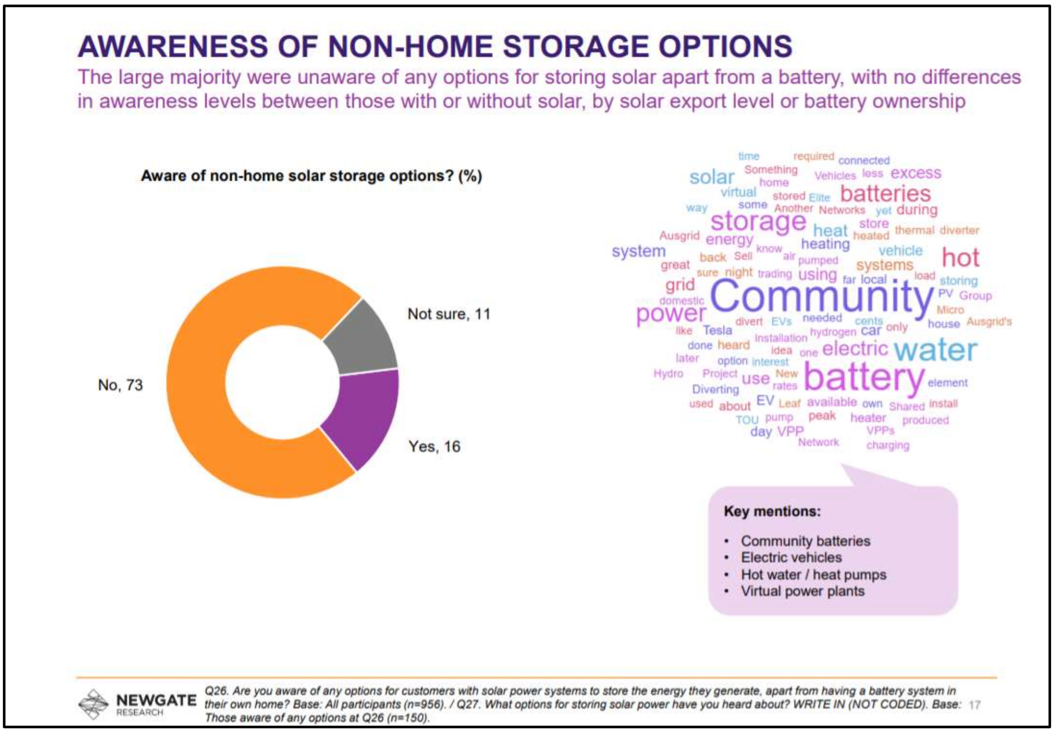
Some of the key findings in the report specifically relating to community batteries included:

- Unprompted awareness of any home battery alternative is low, with only 16% of those surveyed stated they were aware of options for customers with solar power to store the energy they generate other than having an individual battery system installed at home.

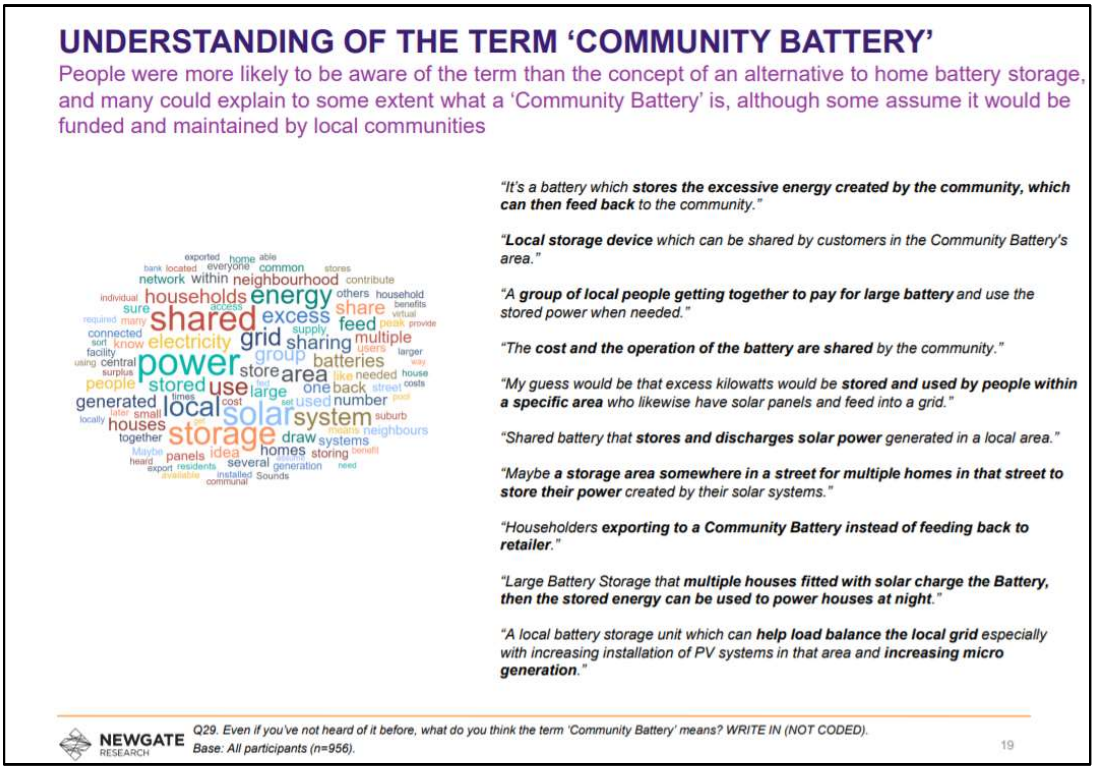
[18] https://www.ausgrid.com.au/About-Us/Innovation/NIAC

[19] www.aer.gov.au/networks-pipelines/compliance-reporting

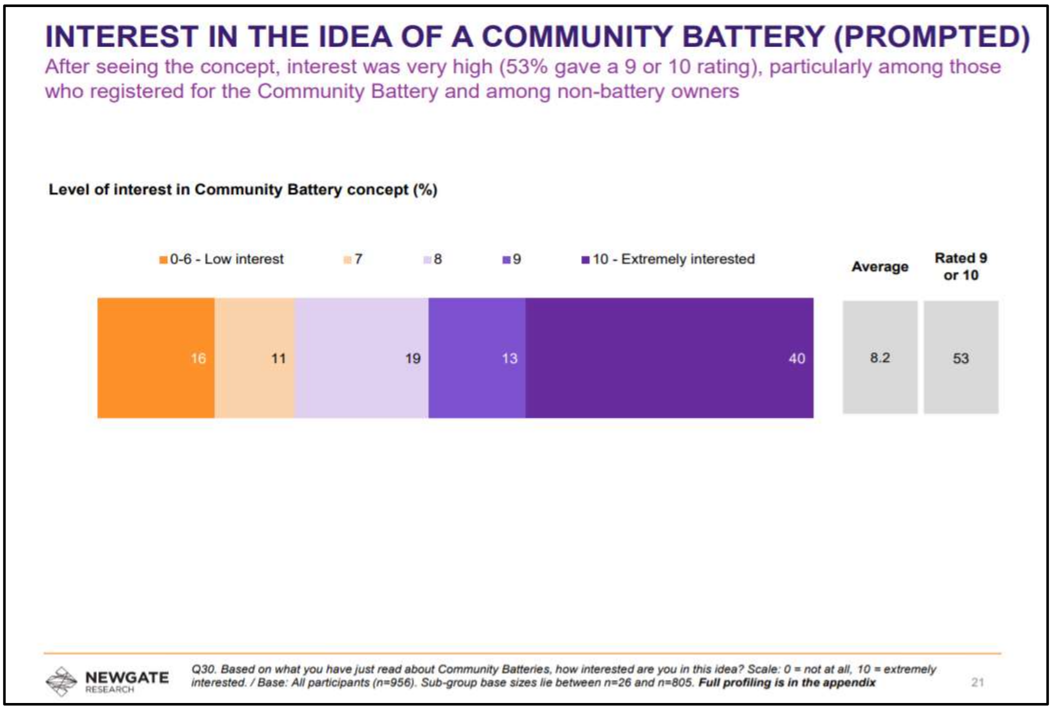
[20] https://www.ausgrid.com.au/In-your-community/Community-Batteries/Project-research



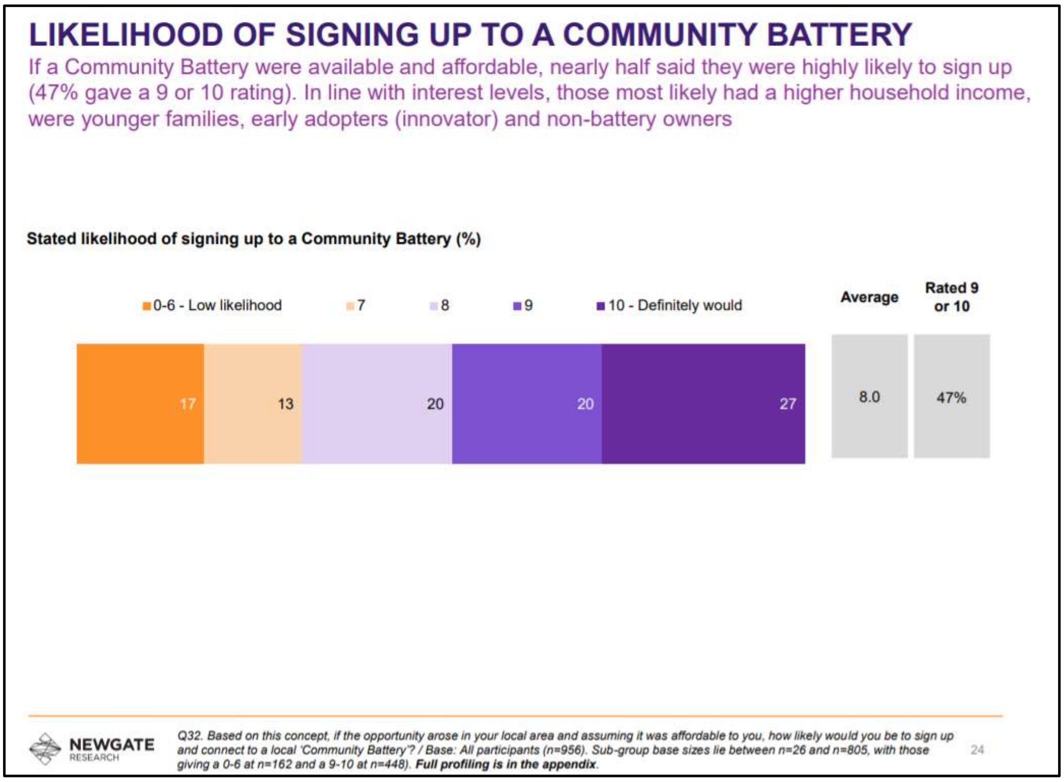
- Those surveyed were more likely to be aware of the term 'community battery' than the concept, with awareness higher among those with larger PV systems and single batteries and early adopters.



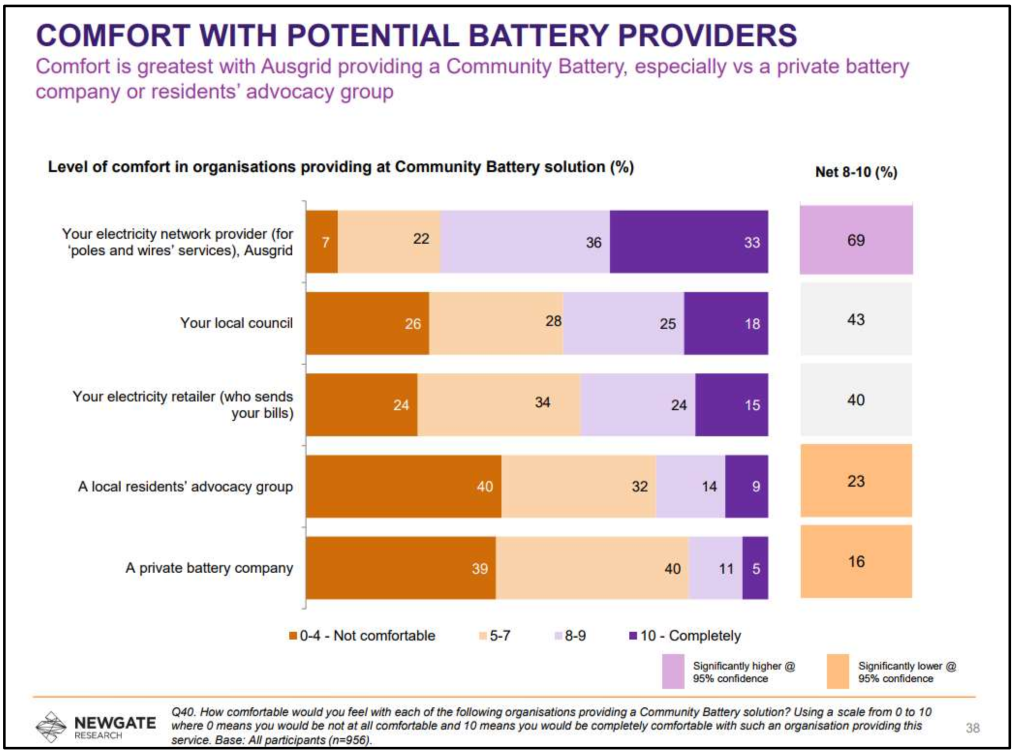
- Following a basic description of Ausgrid's community battery concept, there was a very high level of interest with just over half (53%) rating their interest level at 9 or 10 out of 10.



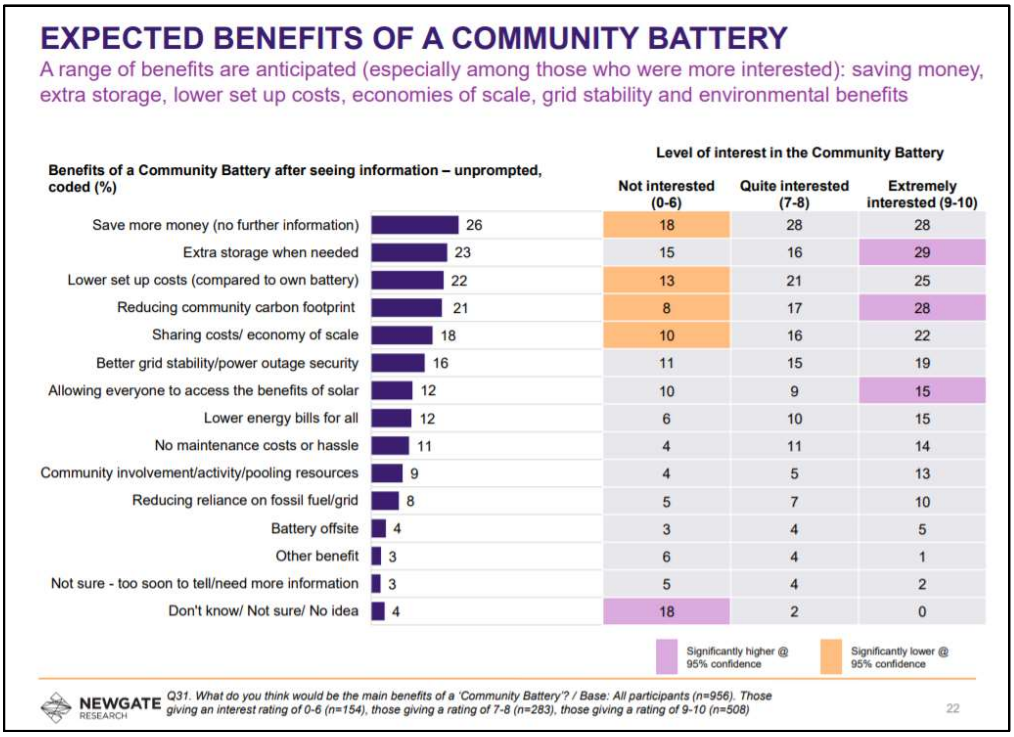
- Further, nearly half said they were 'highly likely' to sign up to a community battery if the opportunity arose in their area and it was affordable



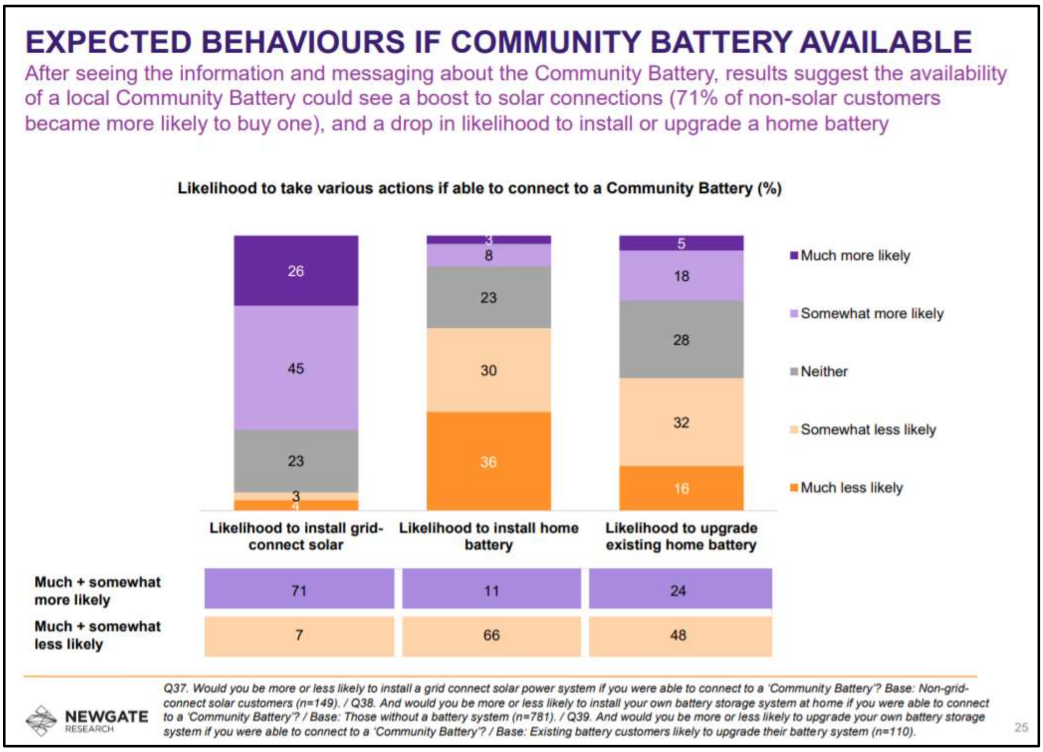
- Customers were asked about their level of comfort with different organisations providing a community battery service, with 67% of customers rating electricity networks at 8 to 10 out of 10. 43% and 40% of customers rated local councils and energy retailers respectively at this comfort level.



- Customers also provided their views on their expectations of the main benefits they would receive from a community battery solution, with the most popular being to save more money, acquiring additional storage, lower set up costs, environmental costs and sharing/economies of scale.



- 71% of non-solar customers surveyed who were considering installing solar within the next 2 years, were either much more or somewhat more likely to take up solar if they had the opportunity to be connected to a community battery.



The results from the survey were then used to inform further qualitative research which was undertaken in December 2020 in a 3 day online forum with a smaller group of Ausgrid customers, to develop and test a theoretical community battery offer for customers that would be developed for the community battery pilot in Phase 3 of the project.

While the majority of the Phase 3 customer trial is funded separately under the Ausgrid Network Innovation program, customer engagement related components of the project such as ongoing support for customers' experience in the trial, will continue to be the ongoing focus for the project for FY22.

The detailed public report containing the results from the survey is available on the project research page on Ausgrid's website[21].

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/sharedbattery. DMIA research results will be published when available 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.

[21] https://www.ausgrid.com.au/In-your-community/Community-Batteries/Project-research

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 2020-2021 regulatory year.

The project is scheduled to be completed in the 2021-2022 regulatory year. As part of Ausgrid's funding agreement with co-funding partner, ARENA, a detailed public report covering the latest project results and key learnings has been published on ARENA's website[22]. This report is also available on Ausgrid's DMIA Research and Trials page at www.ausgrid.com.au/dm

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:

- 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.

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.

[22] https://arena.gov.au/projects/ausgrid-power2u/

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).

Market Models and Area Selection:

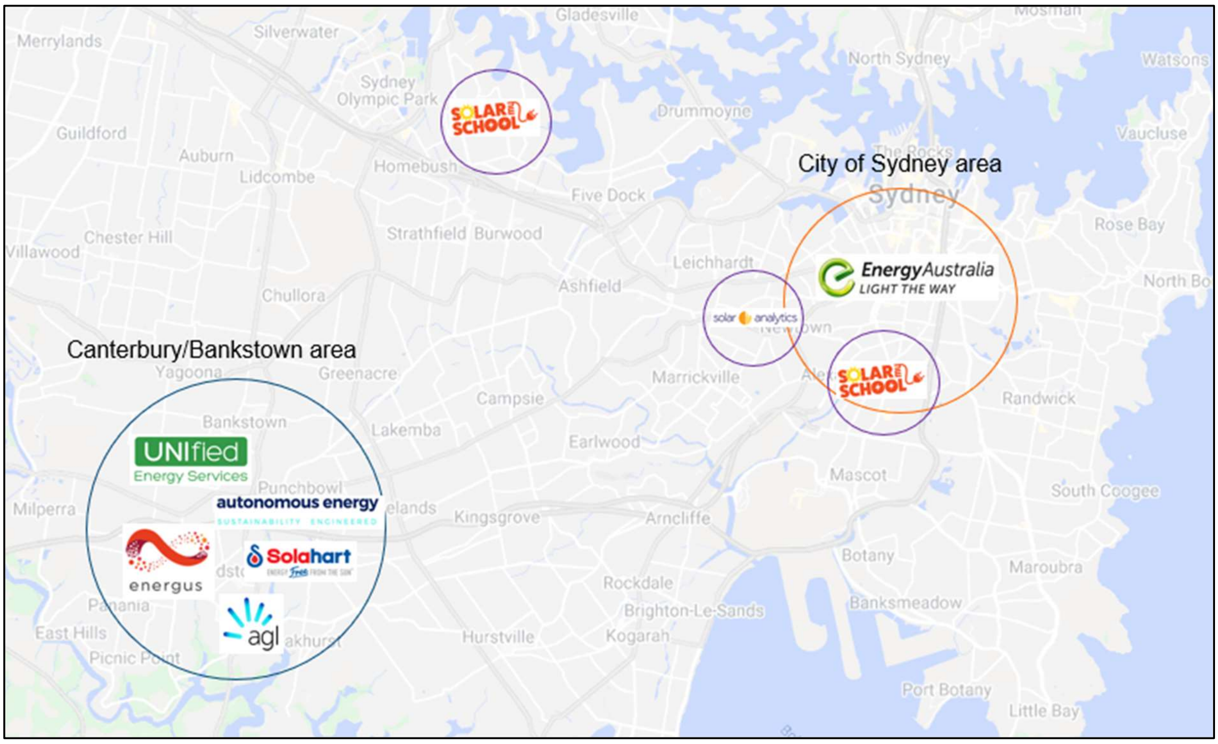
Two main market delivery models were tested as part of the program. For the City of Sydney area (Area 1), a single market provider with a large existing customer base was allocated to operate solely in the trial area, to leverage the benefits in having a large market player participating in the program in return for exclusive access. In the Canterbury Bankstown trial area (Area 2) multiple providers were engaged to achieve diversity in provider scale, manage overall program deliverability risk, and leverage providers' core business which includes technology expertise and specific market segments.

The 2 key trial areas that were selected to offer the incentives were based on the following factors:

- experience of project partners in the area and their ability to service any niche markets in those areas
- locations which had diverse characteristics (e.g. diverse mix of customer profiles and energy loads) so that if future major investment was required to replace aging Ausgrid network equipment, the learnings could be transferrable.

In the City of Sydney area, 12 suburbs were chosen that were typically high in non-residential electricity loads or hi-density residential dwellings which included apartments, semi-detached houses, and townhouses. The Canterbury-Bankstown area was chosen due to having a large number of business customers and its urban setting, where learnings were more reflective of and thereby more transferable to similar areas.

Figure 17: Allocated market provider areas



In addition to the two main geographic trial areas described above, the program also included 2 additional niche market segments, the tenancy market and school sector. A market provider was selected to target each of these segments exclusively based upon past experience and synergies between the program's objectives and their business models.

The market provider assigned to target selected schools had a well-established initiative set up to assist primary and secondary schools take up solar. The program provided a facilitation service via end-to-end support throughout the solar installation process, including a feasibility assessment for the school, information and support accessing grants and funding and assistance with applying for installation with the NSW Department of Education. They were assigned to target selected schools within the City of Sydney and Canada Bay local government areas.

The market provider targeting the rental segment was allocated a dedicated suburb area (Enmore/ Newtown) with a focus on solar for both tenanted residential and commercial buildings.

Incentive Structure Design:

Incentive levels for solar power systems and efficient lighting upgrades were pre-determined for each program area. While Ausgrid paid a fixed per-unit rate to providers for successful sales, the market providers were free to set their own price or structure products when engaging with customers.

A rigorous evidence process was put in place to verify each incentive claim before payment was made. Incentivising a range of permanent demand reduction technologies was considered as part of the program design, and it was decided to launch the program with two demand reduction activities where well-established deemed methods of calculating a kWh reduction for each activity could be utilised. For solar power systems this was based on the rated PV panel capacity installed and for commercial lighting the NSW Energy Savings Scheme deemed method was used to quantify demand reductions.

Program Funding and Monthly Reporting

The overall program budget for the solar and energy efficient lighting was partitioned into initial funding amounts per provider where additional amounts were accessible if a provider exhausted their initial allocation. This was intended to motivate program activity and encourage competition for funds.

The initial funding amounts allocated were based upon the amount of demand reduction activity each market provider had proposed could be achievable in the suburbs of the program area.

Ausgrid conducted monthly meetings with the market providers to monitor progress against these targets and to obtain feedback. Each month, the market providers would submit a program activity report. Once an installation was complete, evidence of the installation activity was required to be submitted to Ausgrid for checking and a payment notice was issued for the appropriate amount based on the evidence supplied. The payments to market providers was jointly funded by Ausgrid and ARENA in the Canterbury-Bankstown program area and by Ausgrid and City of Sydney in the Sydney council area

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 was 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 would 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 were considered included:

- 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 2020-2021, 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 15 - Project Costs

Budget Item	Actual project costs 2020-2021	Total project costs as at end of June 2021	Total expected project costs
Total project costs (excl GST)	$475,029	$1,427,237	$1,500,000

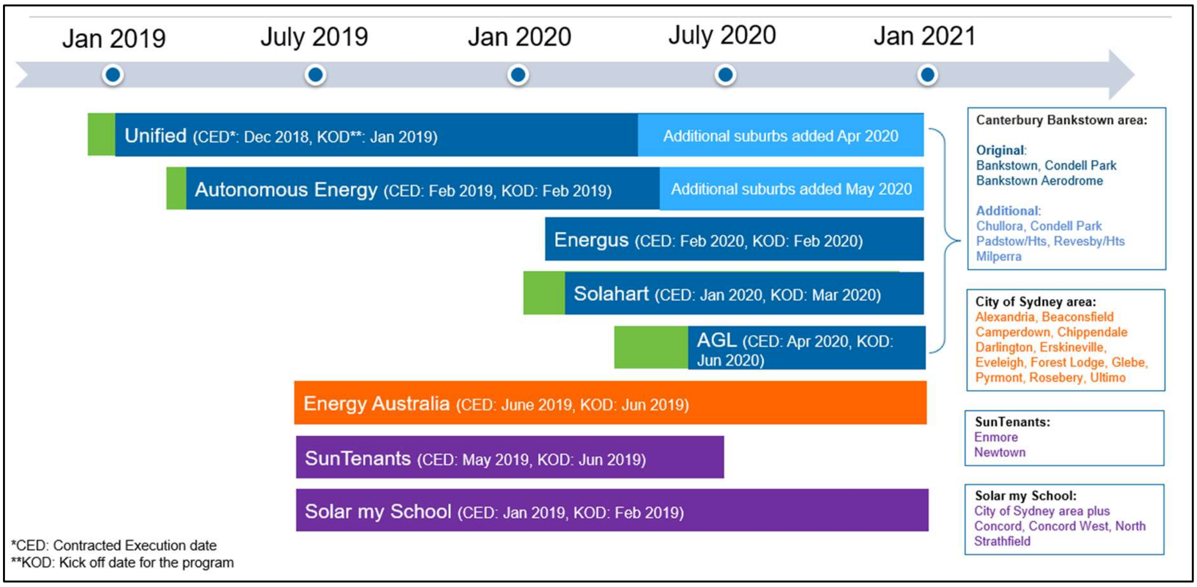
9.7 Project Activity and Results

9.7.1 Summary of project activity to date

Phase 1 - market engagement and provider selection of 8 market providers was completed by 2019-2020. The first 5 market providers had executed their contracts by end of 2018-2019, with the remaining 3 entering the program later in the program by end of 2019-2020.

Phase 2 - program activities were conducted between 2018-2019 and 2020-2021, with the initial 5 market providers commencing their activities in 2018-2019. One of the market providers completed their involvement in the project at the end of this 2019-2020 reporting period. The 3 additional market providers who joined the program later, commenced their activities in the second half of 2019-2020. Of the 7 remaining market providers, all but one completed their committed sales under the program by December 2021, with additional time granted for all committed installations to be completed and verified by 30 June 2021.

Figure 18: P2U Program timeline



The various ways that the incentives were structured or promoted by the market providers in their marketing activities to end-use customers included:

- **Solar Subsidies** where the full $250/kW incentive was not passed on. For example,
    - In the residential market for example subsidies were offered at different dollar amounts based on system sizes e.g. to buy a 3kW system the customer could get an additional $450 rebate, or for a 5kW system the customer could receive a $750 rebate). The remaining portion of subsidies assisted in paying for marketing or resourcing costs.
    - Commercial subsidies were also offered on similar but larger scale e.g. rebates of $15,000 was offered on 100kW systems. The general response to subsidy offers at the lower rates helped to start conversations with potential customers. However, the market providers who started at a lower rate were able to shift to a higher level of subsidy towards the full amount. The increase made a significant difference in motivating customers to act and commit to accepting their proposals.
- **Efficient lighting retrofits** where the end-use customers were offered a free extended warranty on the lighting technology or a reduction in cost based on the $ per Energy Saving Certificate (ESC).
- **Limited offers** where the number of offers available was set to cap. One market provider advertised in their letterbox flyer, "offer limited to 50 households only". However, this did not appear to resonate that strongly and there was only a modest uplift in solar quotations following these types of incentive offers.
- **Limited time offers** on when installations must be made. One market provider in the Canterbury Bankstown area advertised that to receive the offer for subsidies relating to the P2U program, the installation must be made by 30 June 2020 to create a sense of urgency to motivate customers to commit to accepting proposals.

Phase 3 - assessment of trial objectives, reporting and sharing of lessons learned was substantially complete by the Ausgrid project team at the end of 2020-2021. As part of our funding agreement with ARENA, they required completion of our ARENA knowledge sharing report by April 2021. Consequently, the ARENA funded part of the project in the Bankstown area was wound up at end of 2020 with final installations permitted to end March 2021. This report has since been approved and is now publicly available on ARENA's website[23] or on Ausgrid's website via the Demand Management web page for Innovation Research and Trials at www.ausgrid.com.au/dm.

But while the ARENA funded component of the project in the Bankstown area was required to be completed per ARENA's timeline, the schools and City of Sydney components of the project continued until June 2021. This allowed for the extended assessment and tender timelines associated with new solar installations on NSW State schools, as well as additional time for solar and lighting installations to be completed in the City of Sydney area.

Completion of the overall project is expected during 2021-2022 with final reporting of project results provided in the next DMIAM Compliance Report for 2021-2022. An updated knowledge sharing report will also be published on Ausgrid's website.

9.7.2 Update on material changes to the project

This project has been expanded and extended 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 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.

[23] https://arena.gov.au/projects/ausgrid-power2u/

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.

As mentioned in the previous section, due to one of the market providers operating in the program's niche school segment, its ability to facilitate delivery of the school installations was heavily influenced by internal decisions by the NSW Department of Education. The Department has made relatively material changes to its tendering, approval, and installation processes during 2020-2021 that has impacted the timing of the installation of solar systems for the majority of the schools in the Power2U program.

Marketing activities were completed at end of June 2021 with installation of new systems expected to be complete in Calendar 2021.

Further details on trial operational changes are found in the knowledge sharing report published on ARENA's and Ausgrid's websites.

9.7.3 Collected results

Phase 1 was initiated in 2018-2019 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.

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, with one market provider selected to operate alone in one of the trial areas, two market providers to compete and operate in the other trial area. The fourth and fifth market providers were allocated their own niche segments to trial the program in a smaller geographically specified area that focussed on the rental market and the school's segments, respectively.

During 2019-2020, 3 additional market providers were engaged to compete in trial area two to stimulate the level of competition and activity. In addition, the geographic boundaries in this trial area was expanded from 3 suburbs to 12 suburbs. At this time, the decision was made to make several other changes to program operations. These included:

- extending the project duration and customer incentive availability;
- 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.

Phase 2 market provider activities during FY2021 saw an up-turn in activity where committed sales began to increase, which can be mainly attributed to:

- additional market providers increasing competition in trial area two;
- expansion of the trial area two; and
- the deadline the Program put into place for market providers to close their sales pipelines by early December 2020 motivated market providers to close their sales

Sales in energy efficient lighting continued to be very low reflecting the maturity of this segment. Trial area one sales also increased with the number of installations and system size sales, indicating a positive response to the increase in the incentive rate offered by this market provider and more success with companies that were more robust financially to withstand the challenges of the pandemic.

The tables following summarises the results of the trial activities to date. Note that some providers had been operating for a shorter period than others. 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 16 - Power2U Project Solar PV Activity Summary

Provider	Actual sales (kW)		Committed sales (kW)	Totals (kW)
	FY 19/20	FY 20/21		
A	180	396	417	993
B	540	435	0	974
C	0	495	198	693
D	0	315	0	315
E	0	100	0	100
F	0	52	0	52
G	0	106	0	106
Total kW	**720**	**1,898**	**615**	**3,233**

Table 17 - Power2U Project Solar PV Activity by Solar system size

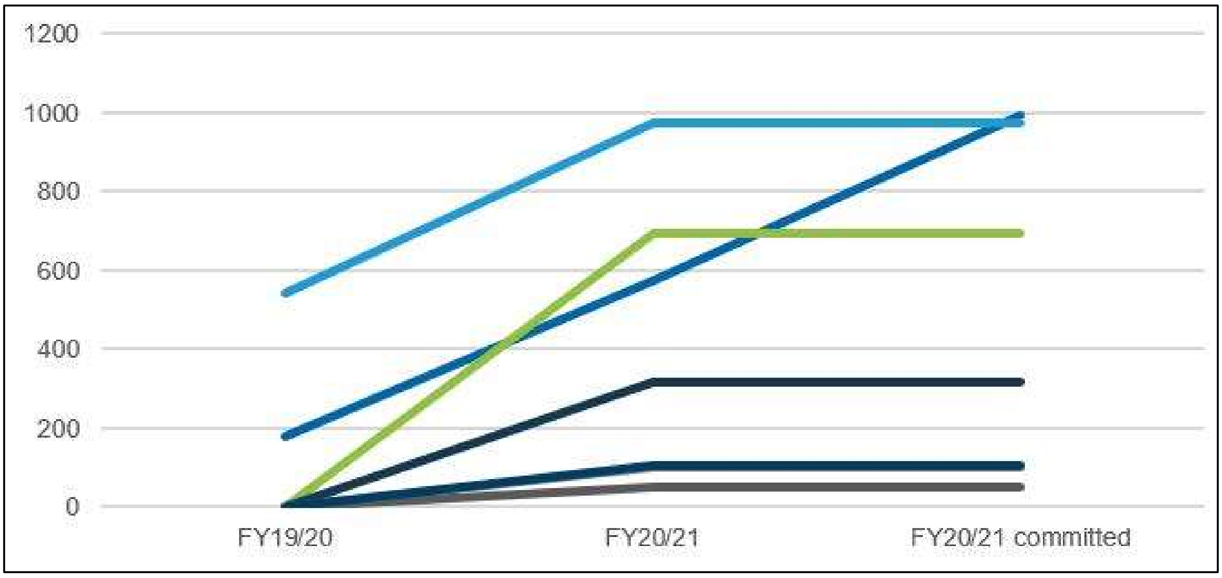
Solar System Size	Business		Residential		Schools	
	Customers	kW	Customers	kW	Customers	kW
0 to 30 kW	29	465	11	66	3	65
>30 to 100 kW	30	1,983			1	41
>100 to 200 kW	4	598				
Total	**63**	**3,046**	**11**	**66**	**4**	**106**

Table 18 - Power2U Project Solar PV Activity by Solar system size

Provider	Area	Lighting Savings (MWh/year)
A	City of Sydney	495
B	Bankstown	85
C	Bankstown	
D	Bankstown	
E	Bankstown	
F	Bankstown	
G	City of Sydney	
Total		**580**

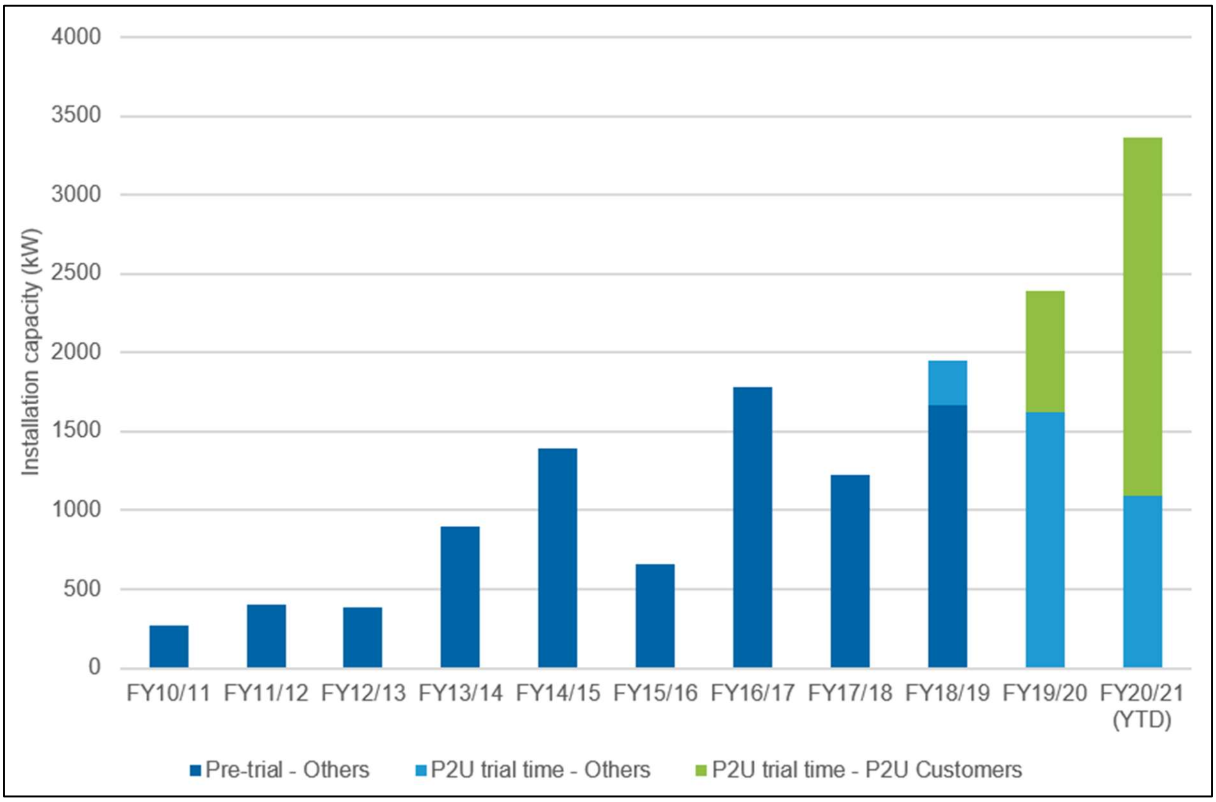
Table 16 is also represented in Figure 19 below, showing the cumulative solar power systems sales over time by provider marked in different colours (excludes the market provider targeting the school segment).

Figure 19: Cumulative and annual solar sales by provider



The annual small-scale solar installation activity across all the P2U program areas is shown in Figure 20 below as installed capacity for non-residential customers. Historically, annual solar installations have grown from a small base of around 200kW per year in FY2010/11 to around 2,000kW per year in FY2018/19, albeit with considerable fluctuation in the intervening years. Against this increasing trend, there does appear to be additional solar activity due to the Program, noting that 2020/21 data is incomplete as it covers only the period to March 2021.

Figure 20: Capacity of P2U program area solar installations per year (non-residential customers)



Due to the program areas covering a diverse mix of customer types, customer sizes and industries, we provide further analysis at more granular levels.

Figure 21: Capacity of Bankstown area solar installations per year (non-residential customers)

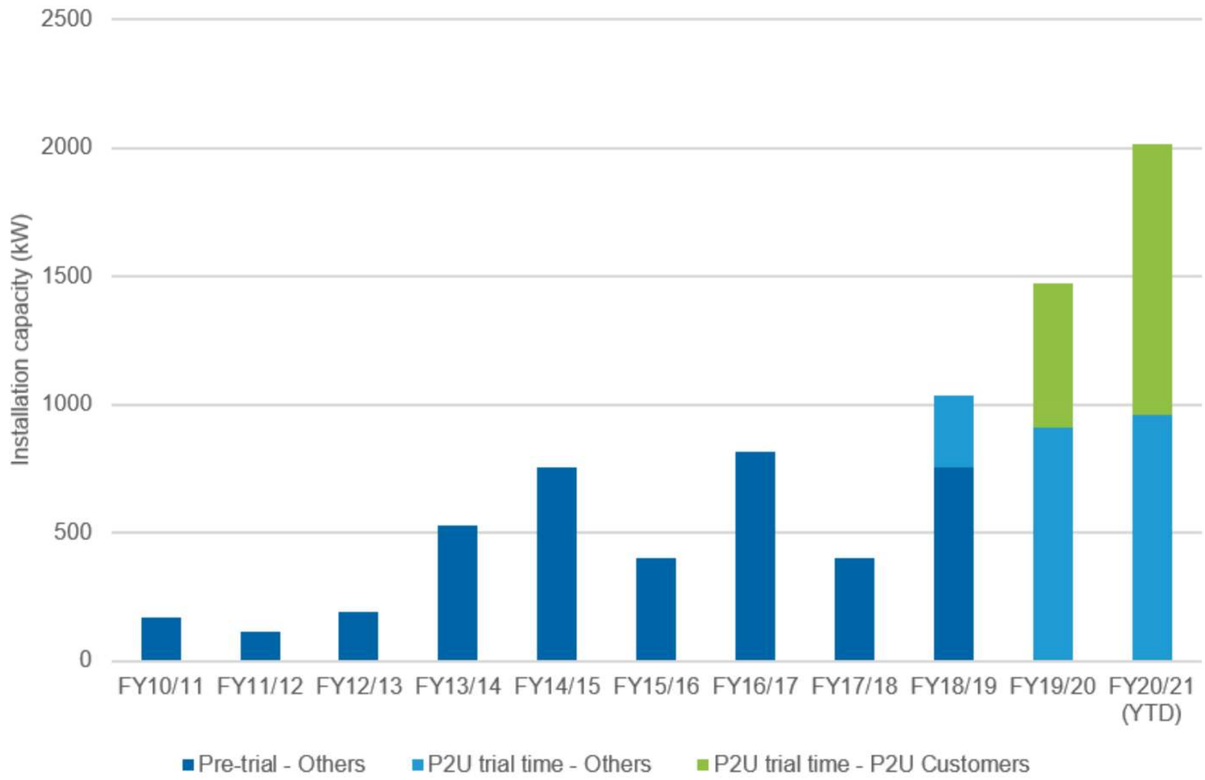
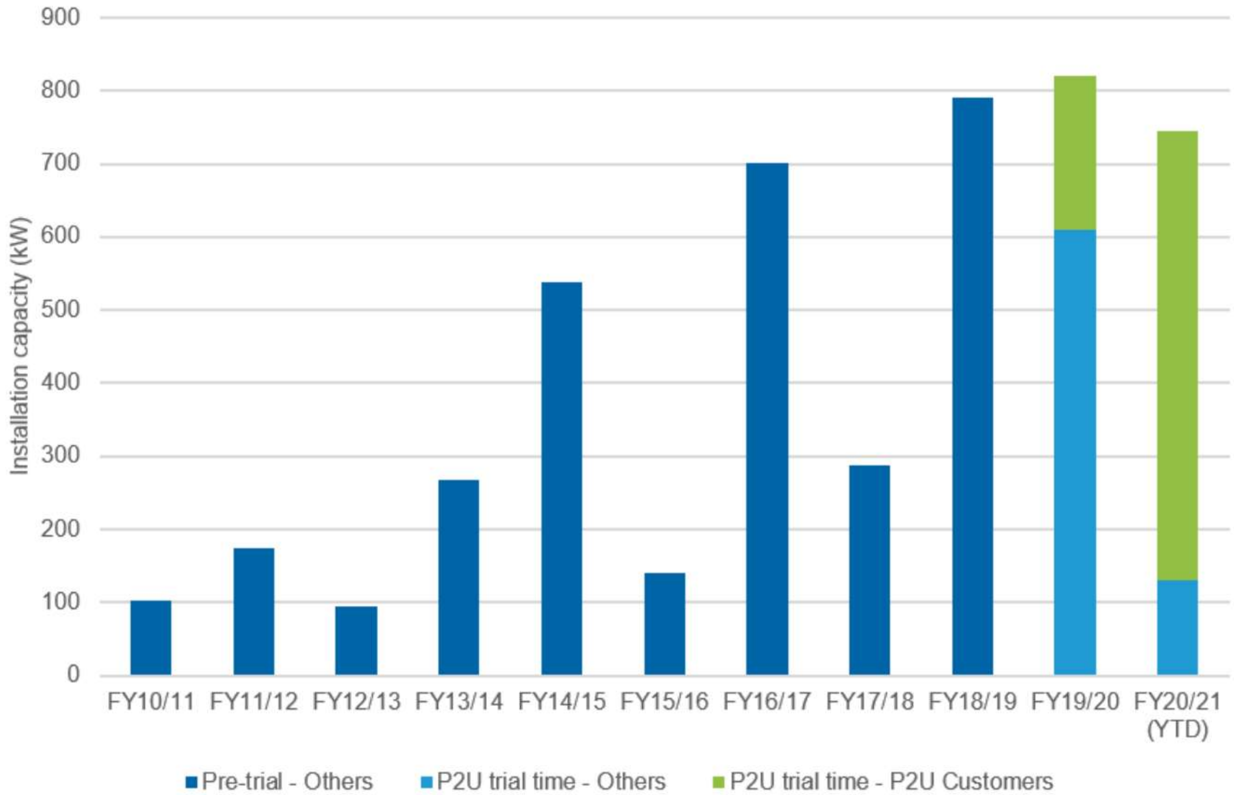


Figure 22: Capacity of City of Sydney area solar installations per year (non-residential customers)



The Program has achieved a noticeable level of additional activity in the Canterbury-Bankstown area (Figure 21) that is above the rate in prior years, noting also that 2020/21 data does not cover a full year as at the publication date of this report. This includes less than 6 months of FY2020/21 when the incentive was available and only 8-9 months of non-P2U solar install activity.

Scaling only the non-P2U activity in FY20/21 (light blue portion of bar) would indicate that total solar installs by capacity in the entire year might be as high as 2300-2500kW. And if the P2U incentive had been available for the entire year, it is possible that the volume of solar activity in FY2020-21 may have been much higher, in the order of 3000-3500kW.

For the City of Sydney area (Figure 22), the level of installations achieved by the Program for 2019/20 and 2020/21 in this area are similar to that in 2018/19, noting that 2020/21 data does not cover a full year as at the publication date of this report. This includes less than 6 months of FY2020/21 when the incentive was available and only 8-9 months of nonP2U solar install activity. Scaling the non-P2U activity in FY20/21 (light blue portion of bar) would indicate that total solar installs by capacity in the entire year may be as high as 900-950kW. And if the P2U incentive had been available for the entire year, it is possible that the volume of solar activity in FY2020-21 may have been much higher, in the order of 1000-1500kW.

An important consideration for this area is the possible impacts from Covid-19 restrictions which impacted the City of Sydney area more so than many other areas in Sydney. A more detailed analysis of solar connections data as it become available, may aid in determining the scale of the impact.

Detailed analysis by suburb, network asset and ANZSIC code are included in the published report on ARENA's and Ausgrid's websites.

And while a quantitative estimate of the level of additional activity remains challenging, our market partners provided their own qualitative assessment of the program. Anecdotal comments from market providers included:

- Business customers that were not considering solar or were considering it before the program but were undecided, were motivated to commit because of the generous incentive with a fixed closing date in the near term;
- In their opinion, on average approximately 75% to 90% of successful sales could be considered additional to business as usual. It needs to be considered that there might be a degree of bias in market providers' self-assessments of their own achieved results;
- More than one of the market providers considered the incentives offered by the program as very attractive. Feedback from one provider was that business customers were after paybacks of around 2 to 3 years or better for capital purchases. Paybacks over 5 years were not considered sufficiently attractive;
- From one provider: "I can certainly say the 99kW sale would not have happened without the discount. Out of the 7 active quotes, 4 of those would not have happened without the discount";
- COVID-19 undoubtedly impacted on the decision to invest in solar for a considerable number of businesses. This ranged from a restricted ability to engage potential leads during the NSW lockdown period, such as face to face meetings and site inspections, all the way to the solar investment decision itself when customers were presented with the offer. Feedback from providers indicated that small businesses were most affected by COVID and the least likely to take up the offer. Other businesses were unaffected and COVID did not factor into their decision making; and
- For the Solar my School trial all but one of the schools that signed up to the overall program did so as a result of the offering being directly marketed to the school and there is strong anecdotal evidence that all four installations were directly attributable to the program activity.

Key Insights

A list of key insights, achievements, barriers, and recommendations are detailed in the full published report. A summary of these insights and recommendations are as follows:

- Determination of the level of additionality, or the installation activity the incentive payments stimulated compared to what would have occurred without them (business as usual), is challenging due to the localised area, impacts from Covid-19 restrictions, part year data, and the natural localised variation in customer energy efficiency activity. Due to the very low level of energy efficient lighting installs and likely market saturation of this technology in the trial areas, the additionality estimate is not particularly relevant. For the purposes of our network benefit assessment we have estimated that about 40-75% or about 1300-2400 kW of the total program installs are additional to the business as usual level of activity.

- Analysis of the impact on a local area involved the derivation of a demand reduction density measure across the entire program area. When compared against the use case network need, this reduction fell within the lower bounds of the overall demand management requirements. This indicates that while the incentive program is considered to have delivered energy efficiency activity additional to business as usual, it was not of sufficient scale or density to offer a complete solution to the network need use case. Due to the local nature of network investment needs, this is not unexpected.
- The scale and density of demand reductions offered by any solution type is inherently limited by the customer base and reaffirms that most demand management solutions will be a blend of non-network and possibly partial network solutions. The program though was considered successful in demonstrating that it may be cost-effective to offer incentives to encourage additional uptake of customer solar power systems as part of a blended demand management solution.
- The adoption of a market led approach was found to be effective, in particular where a number of market providers offered a range of competing products and services and often targeted different customer types. A possible extension of this approach would involve setting up an accreditation scheme and opening the program up to any providers who satisfied accreditation requirements. As noted, this approach was deemed impractical considering the complexity, costs and overheads involved for a program of this size and duration.
- The Solar my School component of the program involved a facilitation service and a much lower incentive level as an alternative to the incentive only structure of the rest of the program. While the no-cost facilitation service was popular and engagement with schools high, the slow pace of funding and tendering of the solar installations demonstrates that this market segment requires sufficient time to deliver. The availability of an extended period to complete the energy efficiency investments will be dependent on the nature of the network need. And while the trial did not formally attempt to directly compare the two approaches for the school segment, we would note that no solar installations were completed in the Canterbury-Bankstown area. This may reinforce that for this market segment, facilitation support and not funds are the primary barrier.
- At a more granular level, 85% of the solar systems by capacity, or 80% by count, were installed on business customers belonging to six industry types. The top six industry types by capacity were Retail Trade, Manufacturing, Construction, Accommodation & Food Services Professional, Scientific and Technical Services and Wholesale Trade. These results might be indicative of businesses with premises that are more favourable towards accommodating solar installations, a by-product of marketing efforts by the market providers in targeting these types of customers, or a result of economic impacts from Covid-19 restrictions.

Based on the results of the program, the following recommendations are made:

- Carry out further analysis into the reasons behind the concentration of solar activity in certain business industries types. Possible reasons might include physical footprint, a higher rate of owner-occupied premises, more energy-intensive operations leading to a higher energy bill benefit due to solar or a combination of these factors.
- Complete an assessment of market saturation levels for any targeted energy efficiency solution to inform program design.
- Engage multiple providers to diversify delivery risk and enable a wider range of products and services to customers. This might involve setting up an accreditation scheme and opening the program up to any providers who satisfied accreditation requirements The program results in the Canterbury-Bankstown area and anecdotal evidence suggests that competing providers offering a range of products and services contributes to a higher volume of sales.

- Where outreach to small customers is important, consider a direct to customer offer for small customers to ease marketing efforts by market partners and potentially simplify access to incentives for customers.
- Ensure project budgets include funds for generalised marketing material, possibly developed with market partners, to aid in their marketing efforts. This gives credibility to the program, creates a sense of partnering with the network/community and potentially aids in local awareness. Ausgrid marketing materials (e.g. brand, website etc.) were highly valued by market partners.
- Consider alignment of the program design with existing incentives and subsidy schemes for the demand reduction activities. For example, government schemes for solar or energy efficiency.
- Establish well defined measurement & verification procedures to simplify program administration
- Caution needs to be applied when translating any results to other network supply areas, either within Ausgrid's area or other jurisdictions, since the size of the customer base is quite small at these granular levels.
- A case-by-case assessment should be undertaken to determine the range of appropriate target energy reductions. There might be several 'portfolios' of possible DM solutions that may be constructed, each able to meet the requirements of the demand management opportunity.
- Establish project start and end dates to leverage business investment cycles, provide sufficient time for market partners to gear up and allow customers sufficient time to reach investment decisions. Do not underestimate the time required from customer contact to delivered investment.

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 2020-2021 regulatory year.

The project will be ongoing into the 2021-2022 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 (BMS). 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 19 - Project Costs

Budget Item	Actual project costs 2020-2021	Total project costs as at end of June 2021	Total expected project costs
Total project costs (excl GST)	$355,410	$860,883	$1,180,000

10.7 Project Activity and Results

10.7.1 Summary of project activity and collected results to date

Ausgrid's partnership with Reposit Power[24] 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 process to add new VPP providers to the trial, which received 11 responses from the market. As part of the process, Evergen[25] and ShineHub[26] were selected to join the trial. Ausgrid's VPP fleet has increased

24 https://www.repositpower.com

25 https://www.evergen.com.au

26 https://www.shinehub.com.au

from approximately 350 to 750 battery customers in 2020-2021. With multiple fleets and providers and a range of battery types in the trial, Ausgrid is able to compare different elements to identify how the various providers and batteries perform within a VPP.

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.

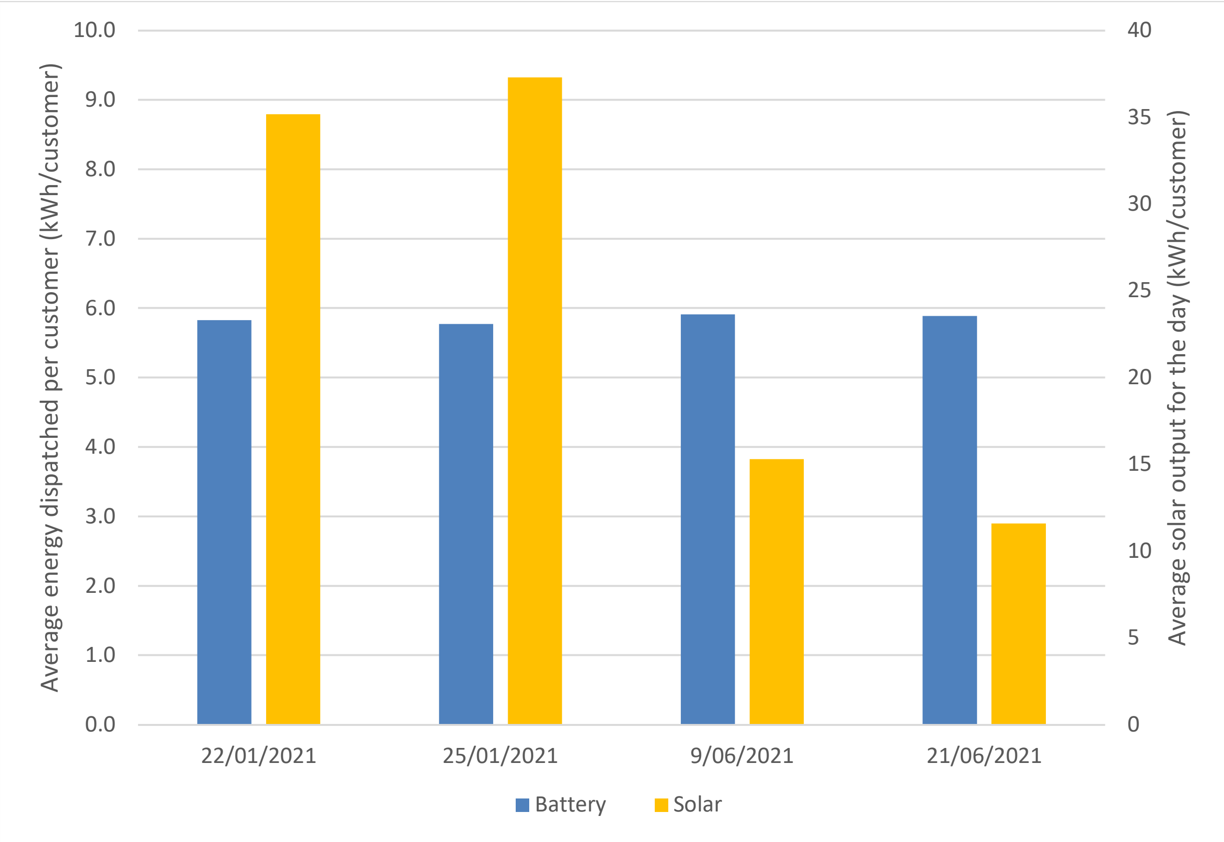
For results from earlier years, please refer to content from earlier AER DMIA reports on the AER's website[27] and published VPP reports on Ausgrid's website[28].

Results from the 2020/21 activities are as follows:

Pre-charging to maximise energy dispatched

Approximately half of the batteries in Ausgrid's VPP fleet have an automatic pre-charge function, where the BMS (Battery Management System) monitors the battery state of charge and automatically charges the batteries prior to a dispatch with the aim of maximising available energy. Figure 23 shows that dispatched energy for a group of batteries with automatic pre-charge function is consistent (+/- 0.1kW) throughout summer and winter days with varying output from their solar system.

Figure 23 - Dispatched energy for a group of batteries with an automatic pre-charge function on different days

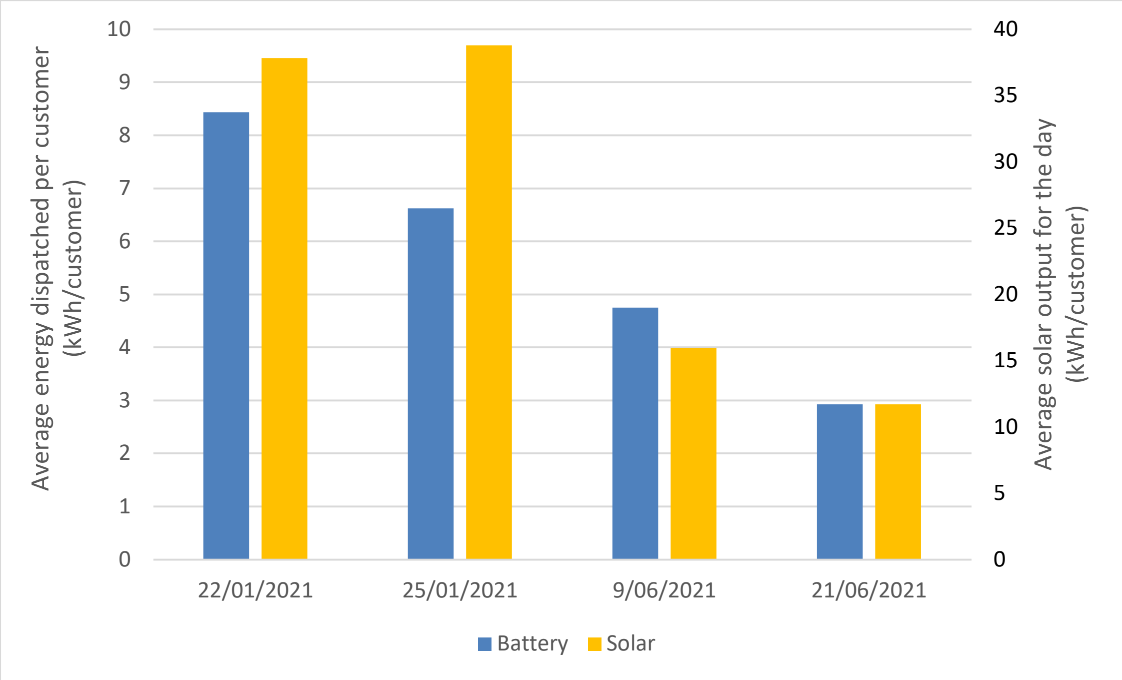


For batteries without an automatic pre-charge function, the dispatched energy is dependent on solar output and customer usage leading up to and during the dispatch. Figure 24 highlights the fluctuations in dispatched energy for batteries without an automatic pre-charge function. While a manual pre-charge can be scheduled for these batteries, it is not as efficient as an automatic pre-charge function where the BMS monitors the batteries and charges the batteries as required.

[27] www.aer.gov.au/networks-pipelines/compliance-reporting

[28] www.ausgrid.com.au/Industry/Our-Research/DMIA-Research-and-trials

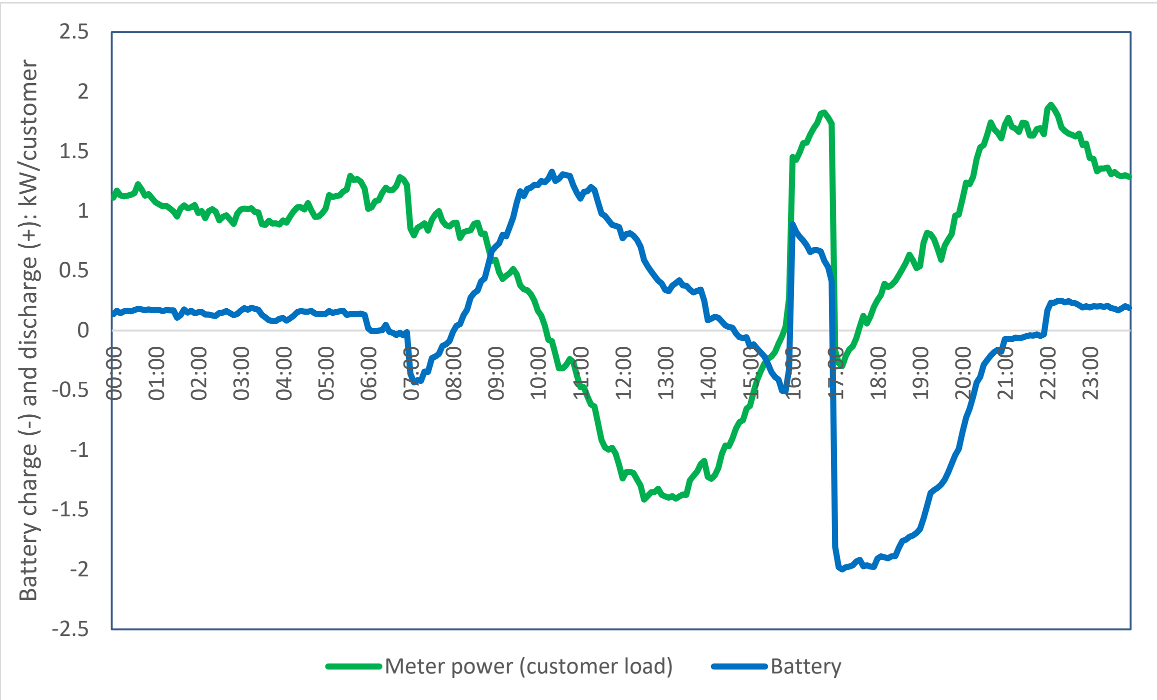
Figure 24 – Dispatched energy for a group of batteries without an automatic pre-charge function



While an automatic pre-charge function is useful for maximising energy dispatched, the pre-charging could potentially increase maximum demand if it occurs prior to a peak demand dispatch.

Figure 25 shows a dispatch that was called one hour prior to the dispatch window (16:00-21:00) which resulted in a pre-charge that increased the customer's load between 16:00-17:00.

Figure 25 - Dispatch for a fleet of batteries with automatic pre-charge function on 29 July 2021

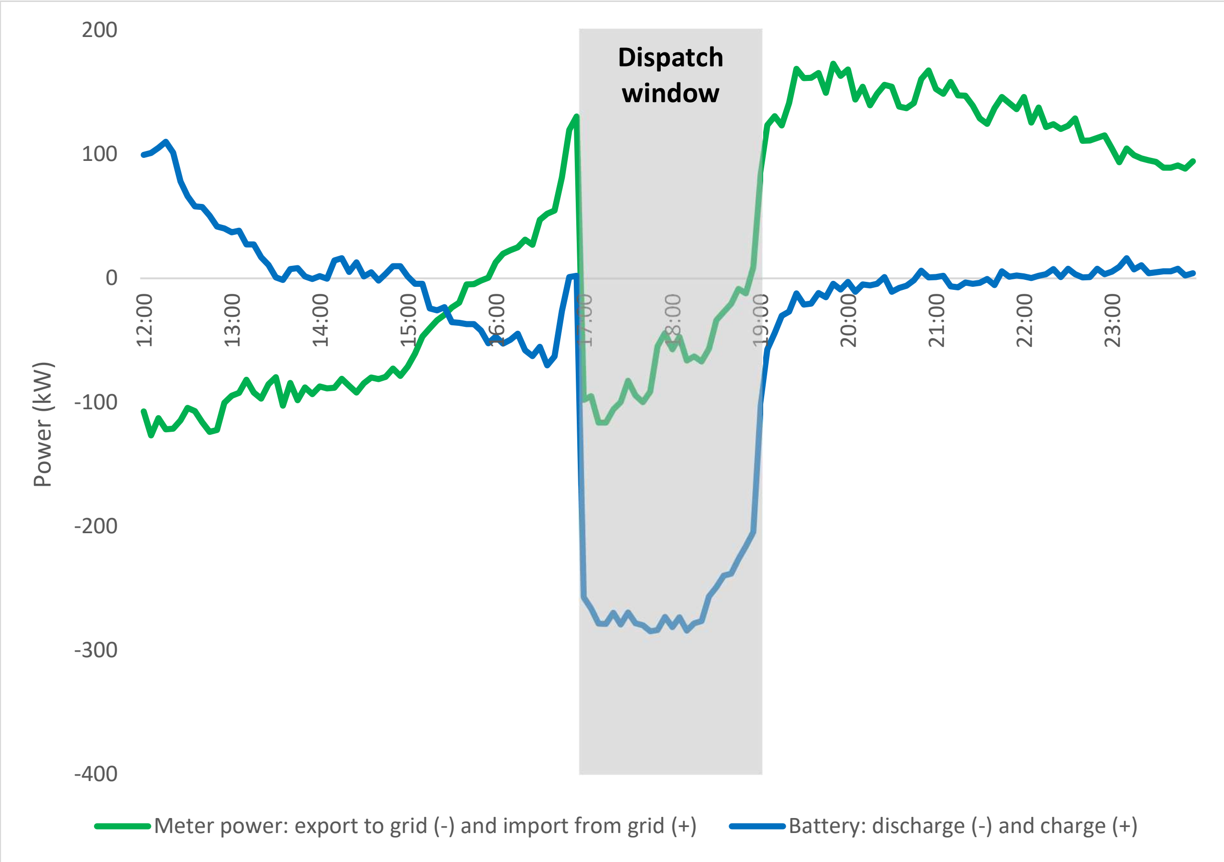


These results highlight the usefulness of automatic pre-charging but also the importance of managing the timing of the pre-charge. Ideally pre-charging should occur during an off-peak or shoulder period however this may not always be possible especially if the dispatch is scheduled with a short notice just prior to the dispatch window. Currently there is no option for the user to turn off the automatic pre-charge or adjust the level of automatic pre-charge. This automatic pre-charging works well for cases where the dispatch is scheduled with advance notice (e.g. 8-24 hours) prior to the event window as the pre-charge generally occurs during off-peak or shoulder period for these cases. However, when an event is scheduled with short notice (e.g. 1-3 hours) prior to the dispatch, the user should be provided with an option to turn off or adjust the level of automatic pre-charge to avoid the possibility of pre-charging during the peak period.

Dynamic dispatch

The majority of dispatches scheduled so far in the VPP trial have been static dispatches, where the aim is to discharge at a fixed level of power throughout the dispatch window without considering the customer's usage. Figure 26 demonstrates an example of a static dispatch (17:00 – 19:00) where the VPP output is relatively consistent and meter power varies throughout the dispatch window due to changes in the customer's energy usage.

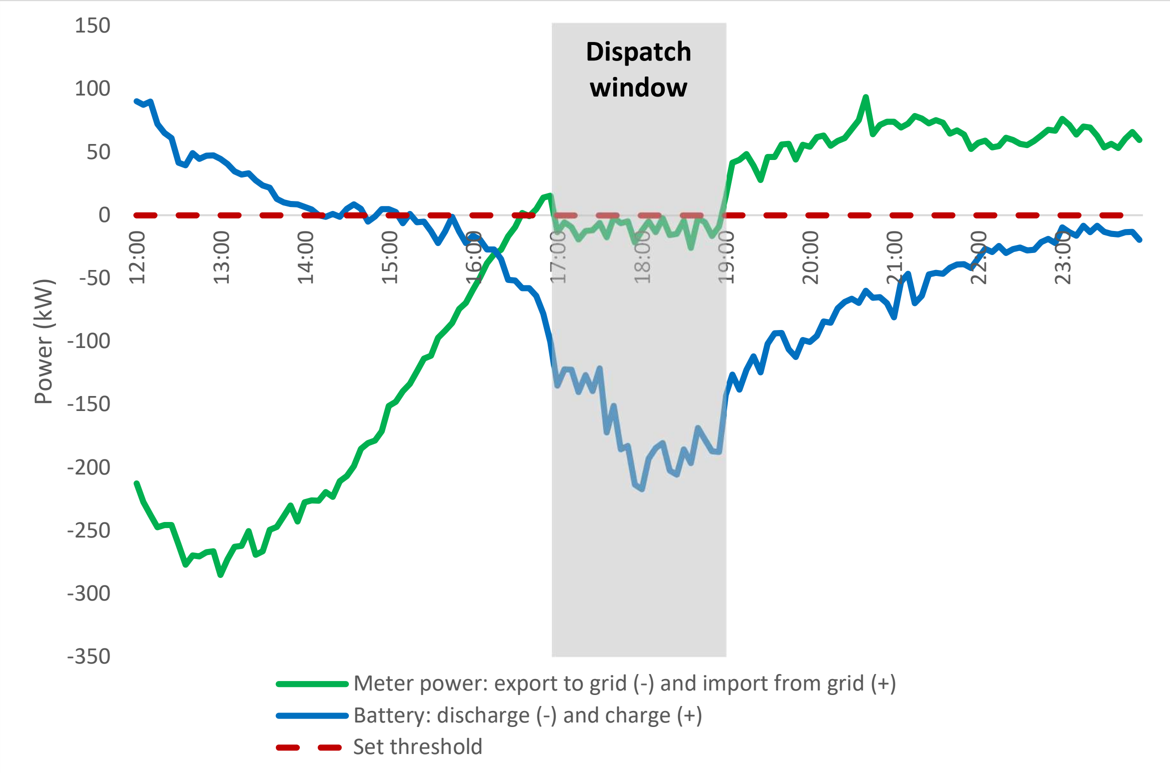
Figure 26 - Typical static dispatch on 26 July2021



Recently, Ausgrid implemented a dynamic dispatch feature, where the battery VPP output is automatically adjusted to maintain meter power below a certain threshold.

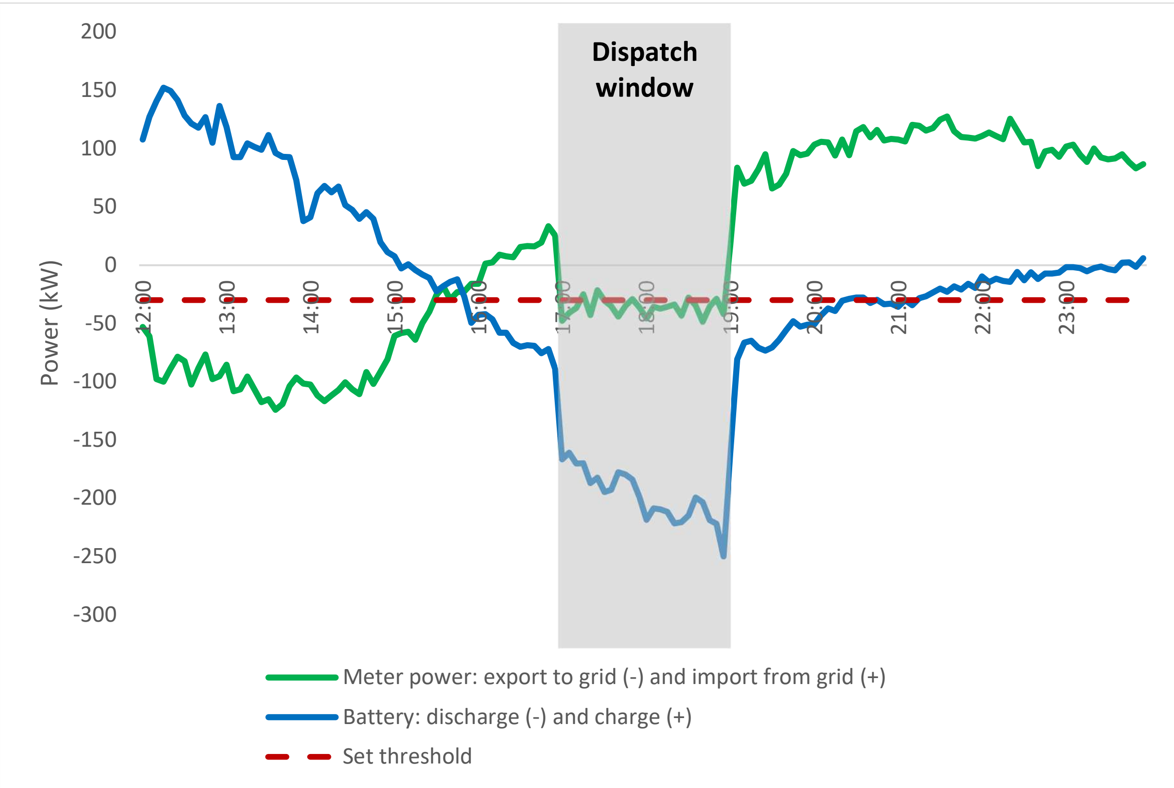
Figure 27 shows an example of dynamic dispatch where the threshold is set to zero (no consumption).

Figure 27 - Dynamic dispatch with threshold = 0 (no load consumption) on 16/08/2021



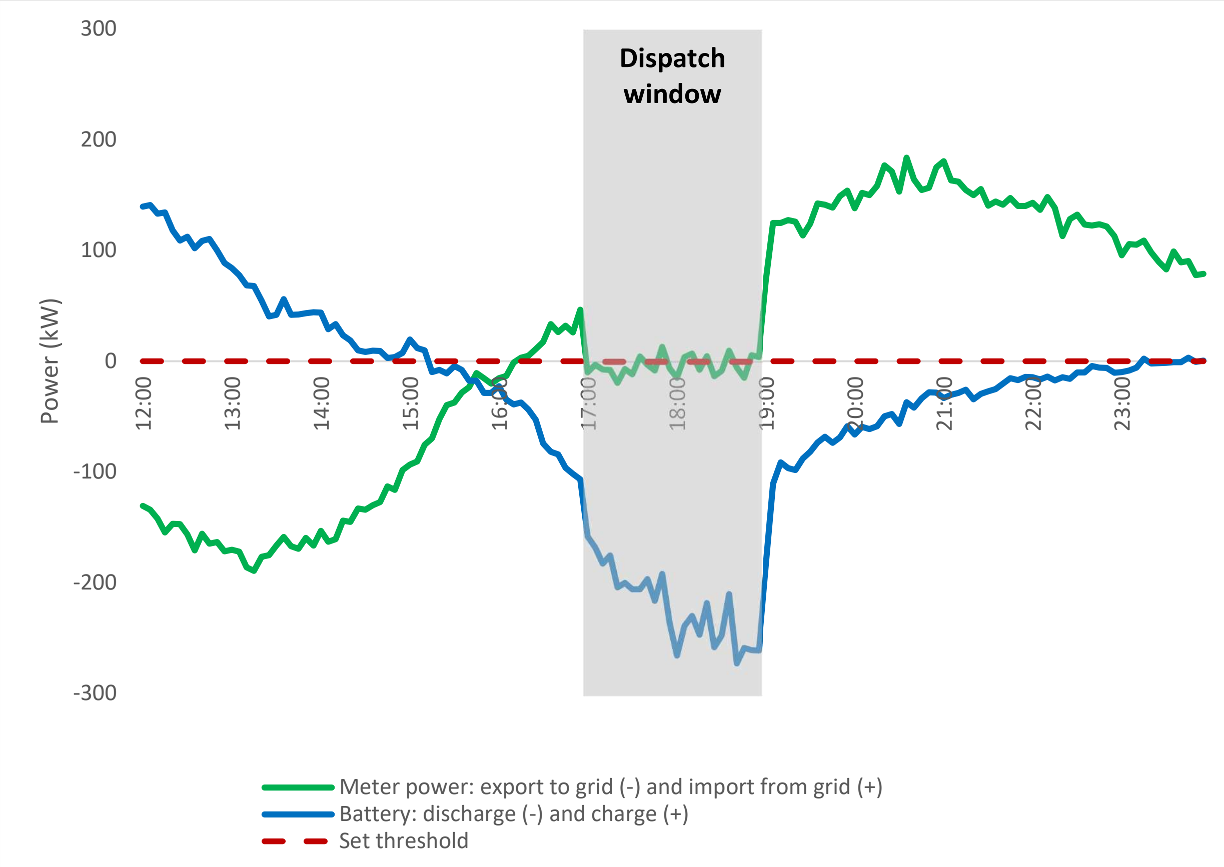
The threshold can also be set to a negative number (export), which means the BMS will adjust VPP output to achieve a minimum level of export at the meter point to assist the grid during peak periods. Figure 28 shows a dynamic dispatch where the threshold is set so that there is a minimum export of 30kW.

Figure 28 - Dynamic dispatch with threshold = -30kW (export) on 31/07/2021



Dynamic dispatch feature does require a reliable communication network as it involves regular communication (multiple times per minute) between the battery inverter and the BMS. Occasional threshold exceedances can be seen in Figure 28 and Figure 29, which can be explained by connectivity issues.

Figure 29 - Dynamic dispatch with threshold = 0 on 22/07/2021



A static dispatch generally involves discharging a maximum fixed amount during an event window. This may be suited for emergency scenarios where a network is overloaded, and the aim is to dispatch as much as possible to reduce the load quickly.

A dynamic dispatch is suited for days when the exact peak time is unknown. Dynamic dispatch can be schedule for longer event window (e.g. 6 hours). The discharge will only occur if the load at the metering point is expected to exceed the threshold and will be adjusted based on the household consumption.

These charts demonstrate the advantages of dynamic dispatch compared to a static dispatch, which include:

- Battery is only discharged when required to meet a set threshold at the metering point
- A more consistent load at the metering point, which assists with network stability
- Allows the network operators to plan and set a threshold that is appropriate to the network constraint at the metering point.

Feed in Management

Instances of higher voltages on local low voltage distributors are increasing as networks continue to experience high growth in new solar PV connections. The local low voltage network and customers' solar installations contribute to the higher voltages which typically arise at times when there is low demand for grid power and high volumes of local solar generation. Solar power systems include solar inverters which are programmed to disconnect or ramp down generation when the local voltage rises above certain limits. A customer's solar power system may be interrupted or reduced in output during these times of local higher voltages.

There are a range of network upgrade options which can alleviate these issues and avoid instances where solar power systems are interrupted or restricted due to high volts. But to explore potentially better ways to regulate local voltage, a Feed in Management (FiM) functionality available with some VPP participants was tested to explore efficacy and reliability.

In November 2020, Ausgrid tested solar Feed in Management (FiM) for a month with 24 battery customers that were part of the VPP trial. The main objective of the trial was to explore the effectiveness of FiM in regulating voltage. The FiM participants had either AC coupled, DC coupled or AC/DC configuration at their house. In many of the sites, compatibility with legacy solar inverter prevented the FiM technology from working as planned. Both gross FiM and net FiM were tested during the trial. Net FiM restricts solar generation to supply customer load and limits the net export to a set threshold. For example, net zero FiM event would restrict solar generation to supply only the load and limit net export to zero. Gross FiM turns off all solar generation.

For AC coupled site (Figure 30), the control function was only set up for the battery inverter and not the solar inverter, which resulted in FiM functionality not working as planned for these sites. Figure 31

Figure and Figure 32 show a lack of response for the FiM events that were scheduled with AC coupled sites.

Figure 30 - AC coupled sites

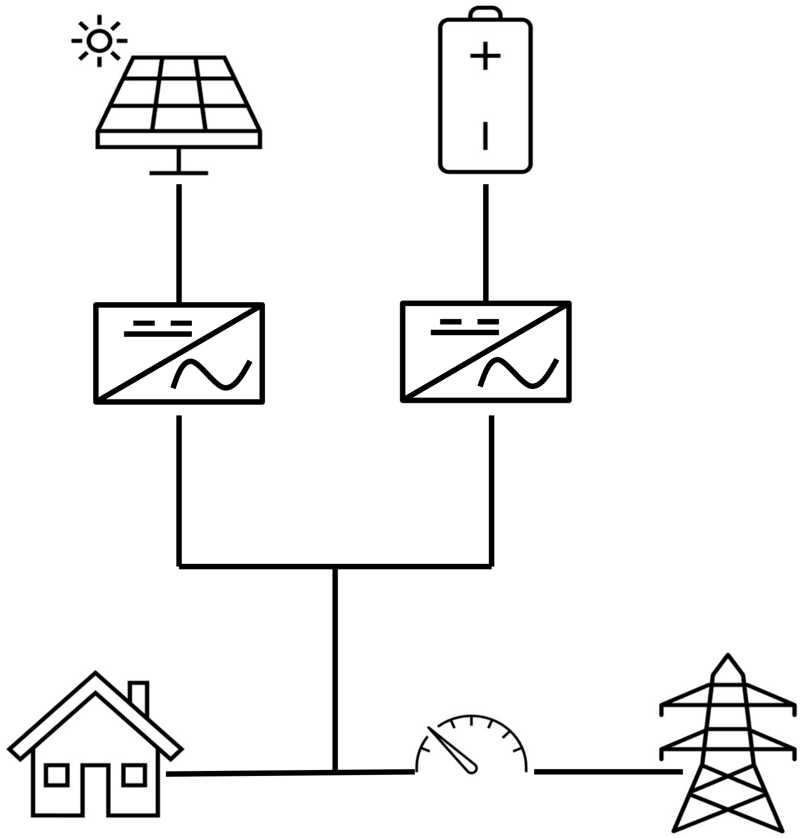


Figure 31 - Demand Profile of AC coupled sites that participated in gross FiM event on 18/11/2021

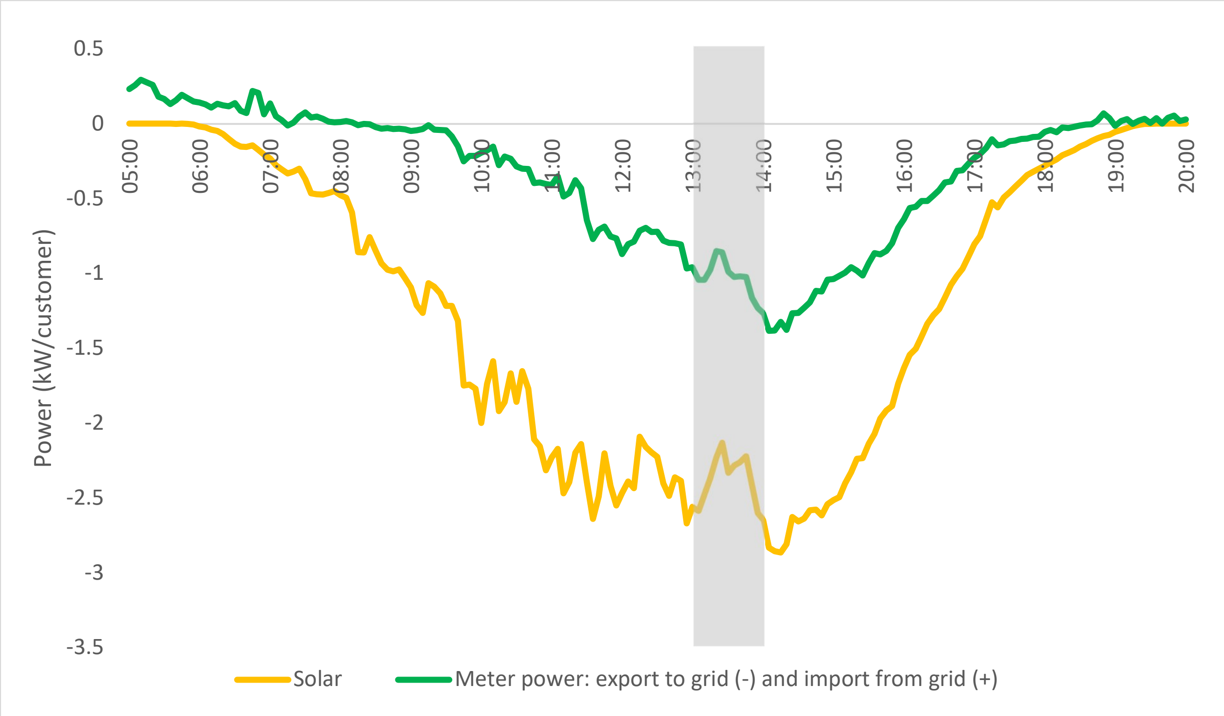
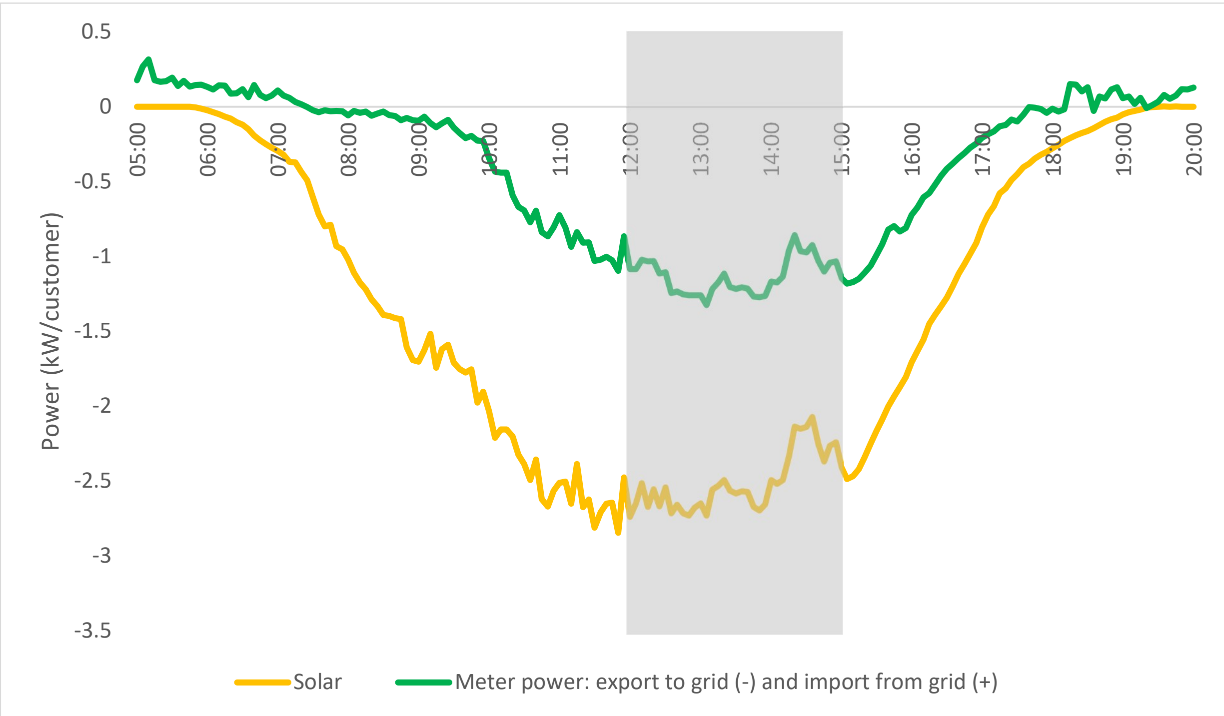


Figure 32 - Demand Profile of AC coupled sites that participated in net zero FiM event on 19/11/2021



For sites with an AC/DC configuration (Figure 33), the control function was only set up for the hybrid inverter with the solar and battery, and not the standalone solar system. Therefore, FiM response was observed for the solar that was connected to the hybrid inverter and not the standalone solar system.

Figure 34 shows gross FiM event where all solar generation was scheduled to be turned off. The results show that only the output from one of the solar systems was turned off while the standalone solar system continued to operate normally. Similarly, only one of the two solar systems seems to have responded to the net zero FiM event on 19/11/2021 (see **Error! Reference source not found.**34).

Figure 33 –AC/DC coupled sites

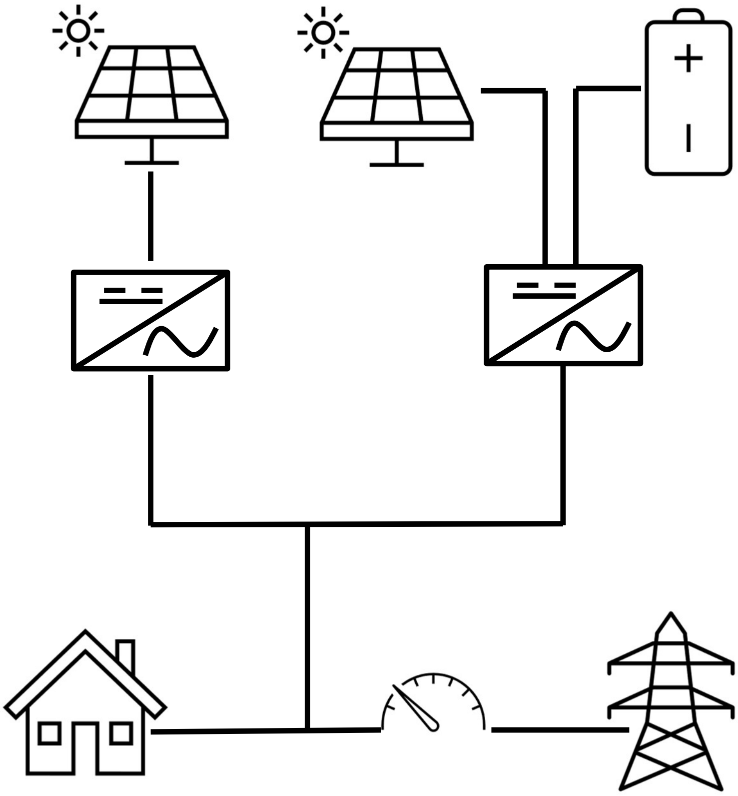


Figure 34 - Demand profile of sites with AC/DC coupled sites during gross FiM event on 18/11/2021

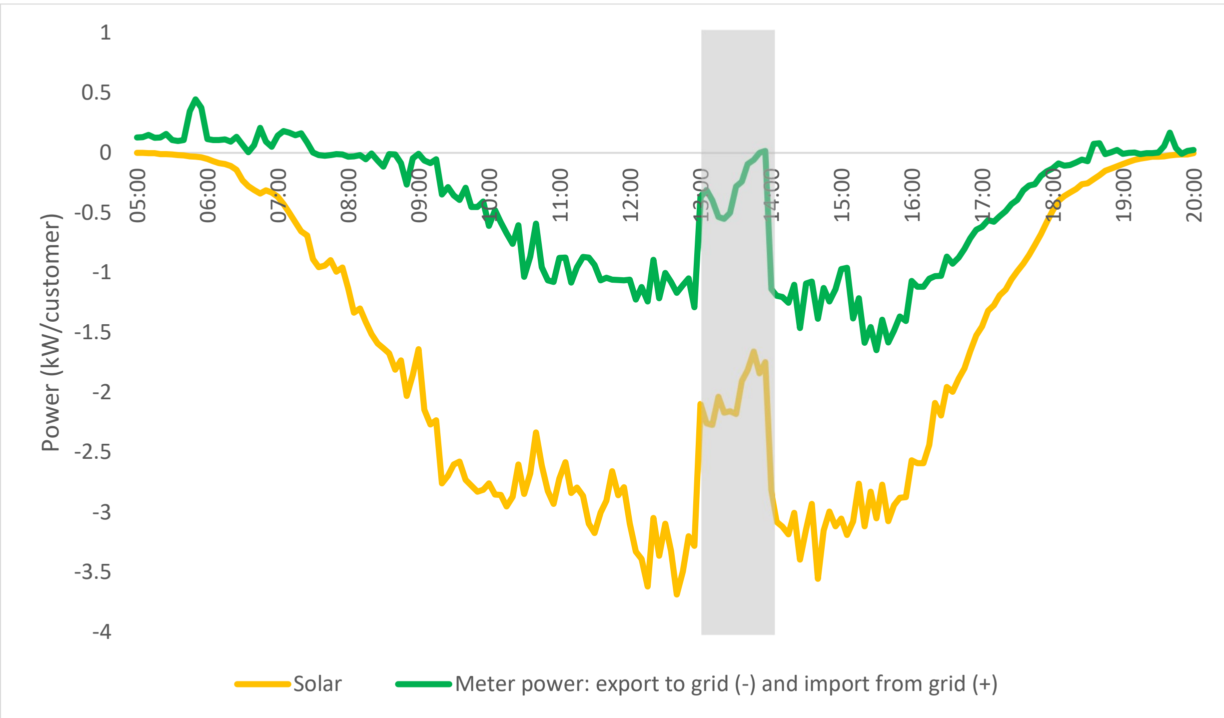
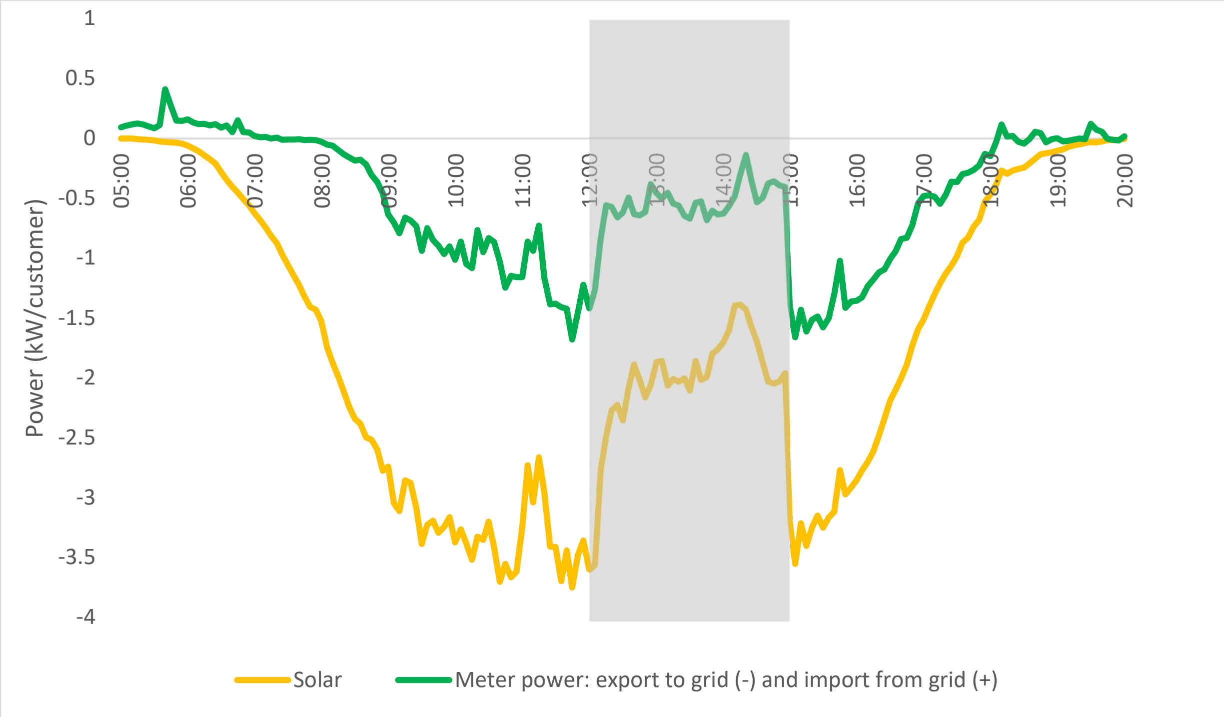


Figure 35 - Demand profile of AC/DC coupled sites during net zero FiM event on 19/11/2021



For DC coupled sites (Figure 36) with only one inverter the FiM functionality generally worked as planned. As shown in Figure 37, the gross FiM event switched off all solar generation, which resulted in the customer having to import electricity from the grid when its solar system is capable of supplying the load.

Figure 36 - DC coupled sites

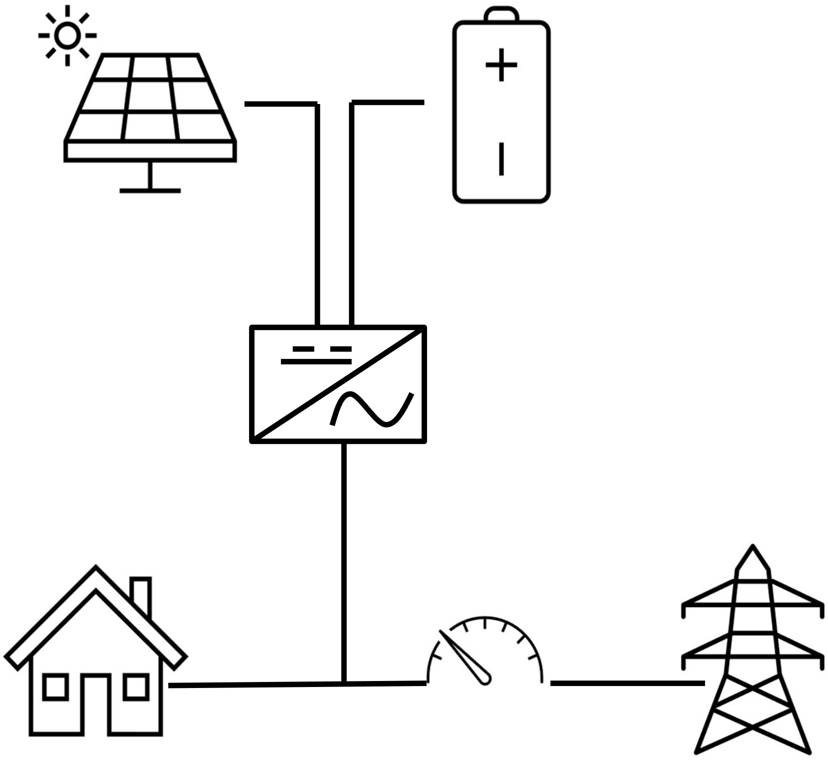
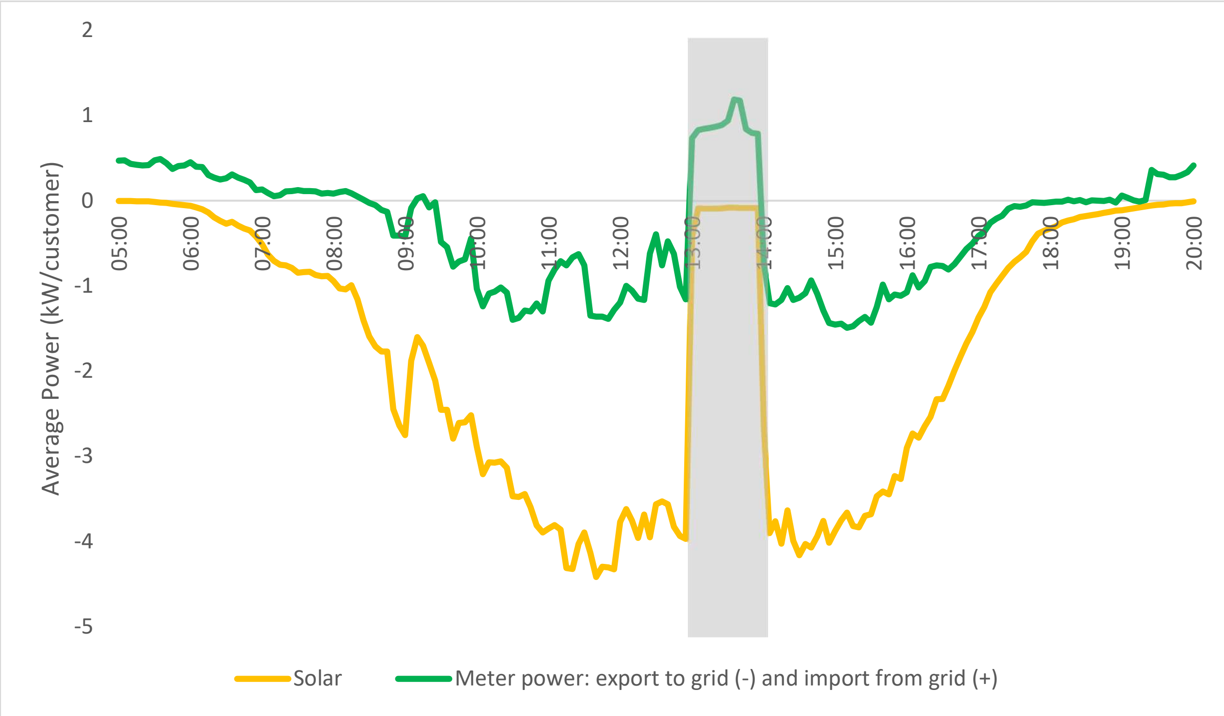


Figure 37 - Demand profile of customers that participated in net FiM event on 18/11/2021



The corresponding voltage chart for the Gross FiM test is presented in Figure 38, which shows that there is a reduction in voltage of about 1.5 volts during the gross FiM event.

Figure 38 - Voltage profile for gross FiM on 18/11/2021

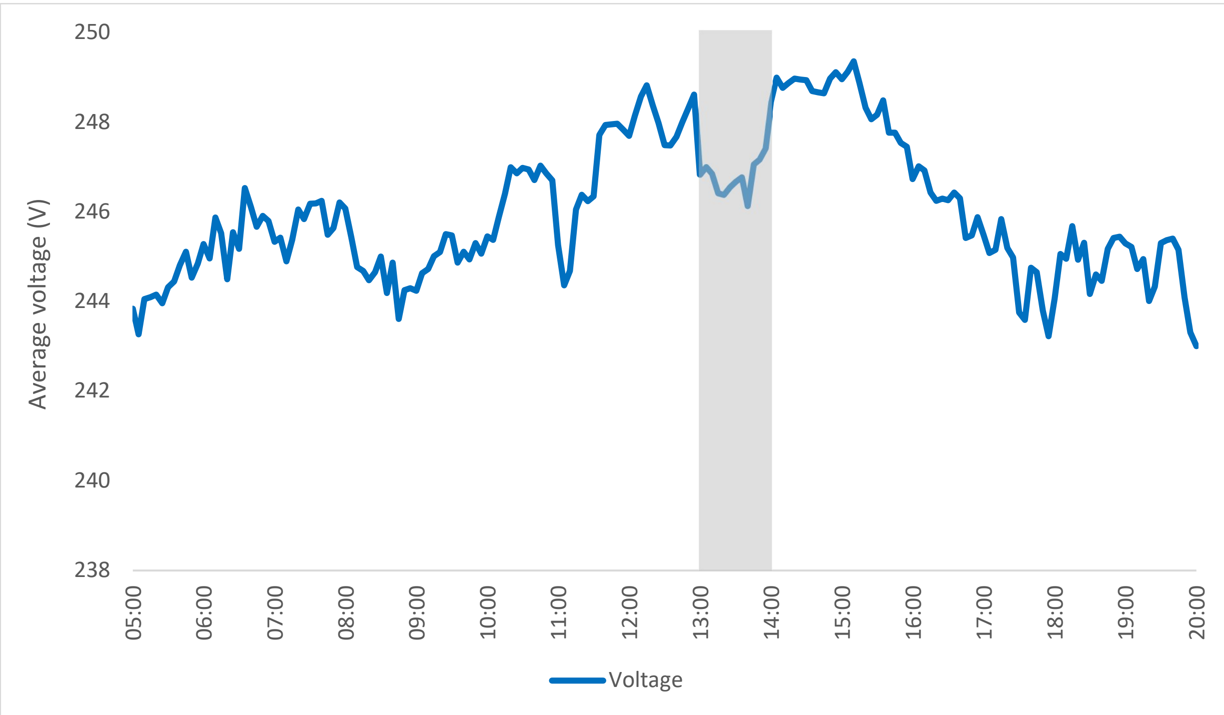


Figure 39Figure shows the results of a net FiM event where the export to the grid is set to zero. The corresponding voltage profile shows a reduction in voltage of about 1 volt that was sustained until the end of the FiM event (see Figure 40).

Figure 39 - Demand profile of customers that participated in net zero FiM event on 19/11/2021

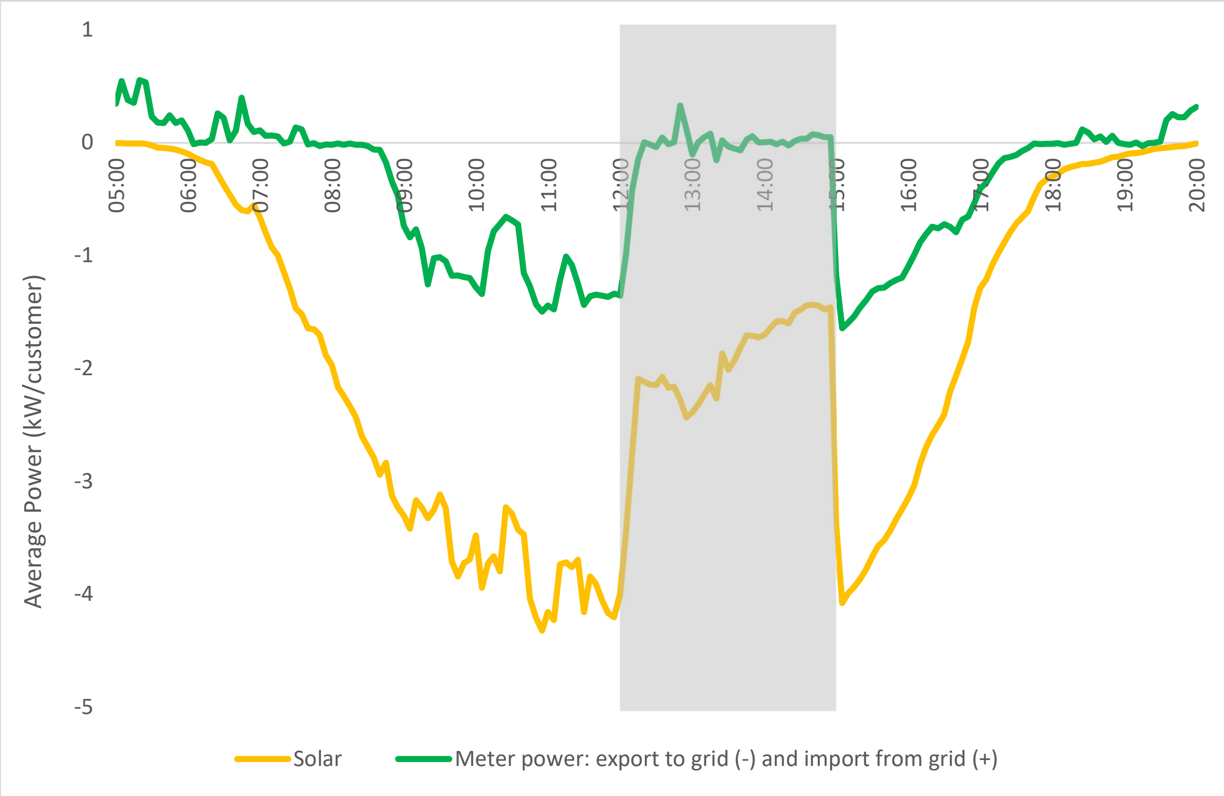
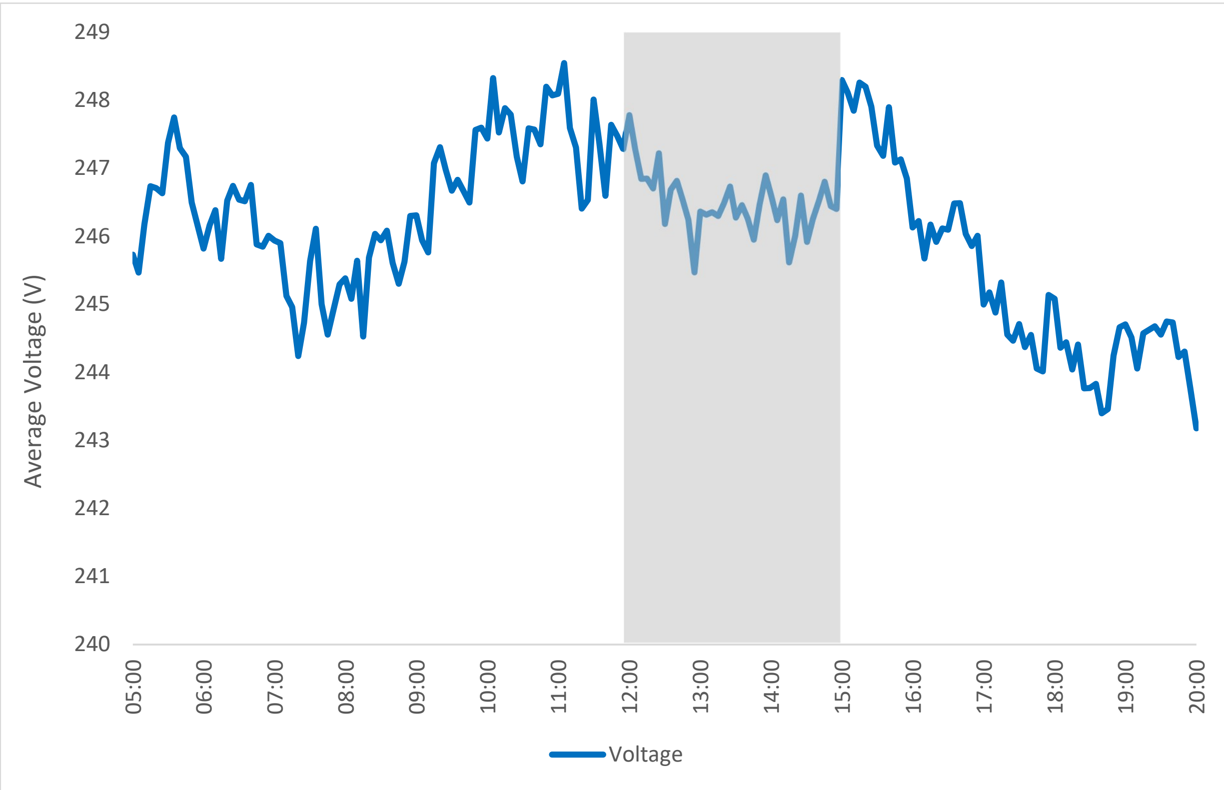
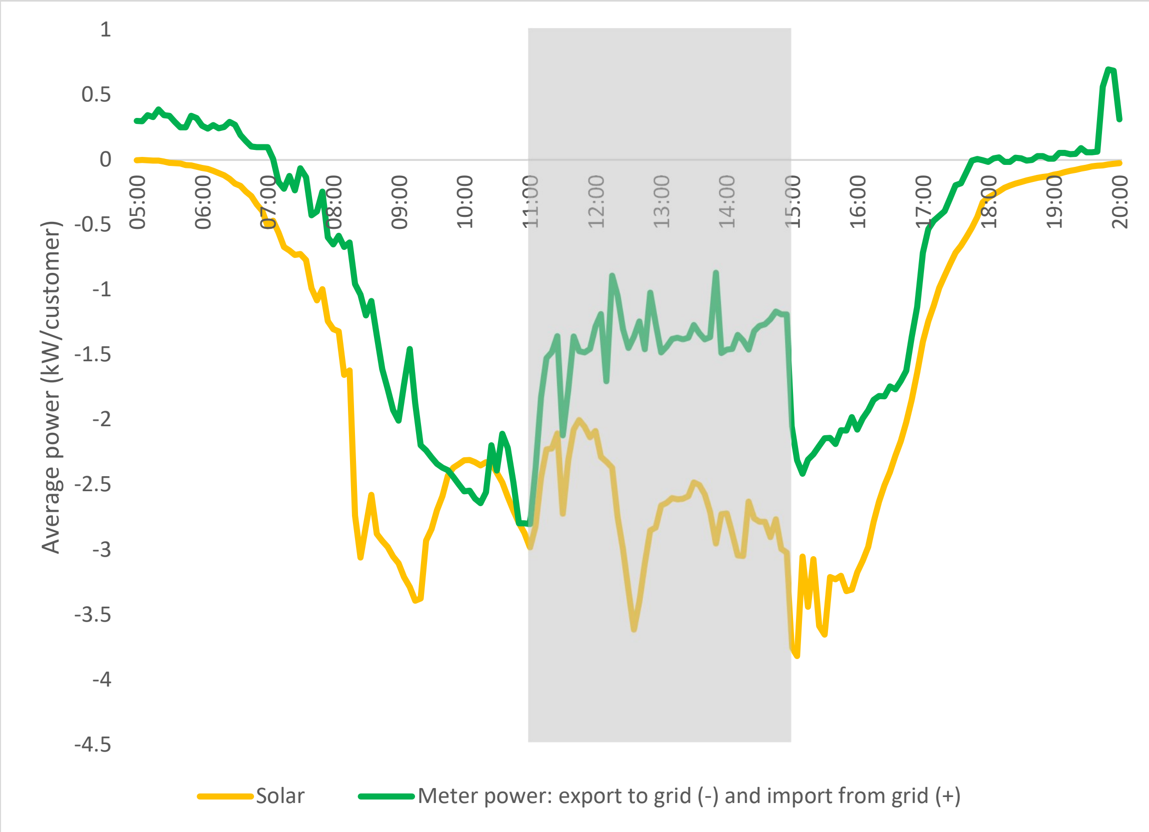


Figure 40 - Voltage profile for net zero FiM on 19/11/2021



The success of a net zero export FiM event depends on the BMS being able to adjust the solar output to a level that meets the load consumption but not enough to export. There were a number of net zero FiM events where the solar output exceeded the load and resulted in export into the grid (see Figure 41)

Figure 41 - Demand profile of customers that participated in net zero FiM event on 25/11/2021



Summary

Key findings from the trial results in 2020-2021 include:

- Automatic pre-charging of the VPP is useful for achieving maximum energy dispatches however automatic pre-charging should be avoided during or close to the peak period. Further investigation and collaboration with VPP providers is required to provide the user and Industry with options to prevent pre-charging during peak period.
- Dynamic dispatch offers a more consistent load profile and better controllability at the metering point when compared to a static dispatch.
- To implement FiM successfully, it is important to ensure that all inverters on site are set up and compatible with the FiM technology. This could be challenging for sites with older solar inverters, which are more likely to have compatibility issues.
- Gross FiM can add cost to the customer's energy bill as it restricts all solar output resulting in the customer having to import grid electricity during solar hours. Payments to customers for market and/or grid support would be required to compensate customers for this.
- Net FiM management is preferable to gross FiM as it allows the customer's load to be supplied by solar while restricting export into the grid. However, net FiM is more complex to implement as the BMS must be able to constantly adjust solar output to supply the load but limit export to a set threshold.
- Both gross and net FiM can assist with lowering voltage during minimum demand days when solar export can cause high voltage levels in the network.

10.8 Other Information

General information about the VPP project can be accessed on Ausgrid's Demand Management web page from the Innovation Research and Trials link: https://www.ausgrid.com.au/Industry/Demand-Management/Power2U-Progam/Battery-VPP-Trial .

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.