DMIS Annual Report 2020-21

Public version

September 2021

Demand Management Incentive Scheme Submission

September 2021

Contents

1 Introduction

This submission has been prepared under the Demand Management Incentive Scheme (DMIS) applied to Ausgrid by the Australian Energy Regulator (AER).

Under Section 2.4 of the AER's Demand Management Incentive Scheme for electricity distribution network service providers 2017, Ausgrid is required to submit an annual report on expenditure under the DMIS for each regulatory year. The annual report must include:

1. Information on **committed projects** (Part A) and **eligible projects** (Part B).
2. For each **committed project**:
    a. The volume of demand management delivered,
    b. An estimate of the realised benefits,
    c. The total incentive to be claimed.
3. For each **eligible project** identified as a preferred option:
    a. The present value of costs and benefits,
    b. A description of responses to the **request for demand management solutions**
        i. Description of proposal,
        ii. Proposed costs and deliverables,
        iii. For a potential credible solution, an estimate of the project's net benefit.
    c. If the project is to proceed as a committed project, whether the project will occur via a **demand management contract** or via a **demand management proposal**.
    d. The expected costs of delivering the demand management solution.
    e. The kVA per year of network demand able to be called upon, influenced, dispatched or controlled.
4. Any projects where a decision has been made to defer or not proceed with an **eligible project** that previously (either in 2019/20 or in previous years) was to proceed as a **committed project,**
5. Any projects where a decision has been made to proceed with a **network option** to meet an identified need that previously was to proceed as a **committed project**.

This submission details DMIS projects undertaken by Ausgrid in the 2020/21 financial year.

2 Governance

2.1 DMIS projects in 2020/21

There was one (1) **committed** demand management projects and one (1) **eligible** demand management project under development in 2020/21.

The eligible project is for the same area as the committed project however, the proposed scope of the demand management solutions is expected to change. This is outlined in section 4 below.

2.2 Compliance with the DMIS

This report has been written in accordance with section 2.4 of the AER’s Demand Management Incentive Scheme (Dec 2017).

2.2.1 Demand management project selection criteria

Ausgrid applies cost-benefit assessment to determine whether demand management solutions can reduce demand and/or defer network investment as part of its network planning processes. The cost-benefit assessment is based on net present value (NPV) assessment where all relevant costs and benefits for the preferred network option as well as various demand management deferral options are quantitatively assessed.

For the network option these costs and benefits include:

- The expected capital cost of the preferred network option;
- The expected benefits of implementing the preferred network option which include benefits associated with:
    - Avoided supply interruptions to customers (unserved energy);
    - Avoided maintenance of aged network assets;
    - Avoided environmental impacts; and
    - Avoided safety risk.

For the various demand management deferral options these costs and benefits include:

- The expected costs of delivering demand reductions;
- The time-value-of-money benefit associated with deferring the network option;
- The avoided unserved energy for a given quantum of demand reductions; and
- An option value benefit.

Both the preferred network option and demand management options include a terminal value benefit in the NPV assessment.

The option with the highest net present value is preferred.

3 PART A – Committed Projects

3.1 Gillieston Heights demand management project

The Gillieston Heights demand management project was first identified as an eligible project in Ausgrid's 2018/19 DMIS Annual Report.

The project was conceived initially based on delivery of peak demand reductions using residential air-conditioning load control (ACLC). Following a customer acquisition process where customers in the subject area were invited to participate, a Demand Response Enabling Device (DRED) was installed on their aircon units to allow Ausgrid control signals to be received. Participants were rewarded based on a sign-up payment and a participation payment awarded at the end of each year.

The Gillieston Heights demand management project built upon learnings gained from Ausgrid's prior Coolsaver trials. The Coolsaver trials employed SMS-control and ripple-control DREDs. The ripple control method was chosen for the Gillieston Heights project principally due to it being a lower cost method and so able to fit within the available budget.

3.1.1 Past implementation

2018/19 Report

This project was first reported in the 2018/19 DMIS Annual Report as an Eligible Project. In section 4.1.3 of the 2018/19 report, we described how, in accordance with the **minimum project evaluation requirements** of the DMIS, we issued a **request for demand management solutions.** We received no viable submissions from the market. After an assessment of internal capability, we determined that this project could proceed as a **demand management proposal** using principally an air-conditioning load control solution developed as part of an earlier Ausgrid innovation project. For further details, please refer to Ausgrid's 2018/19 DMIS Annual Report at https://www.aer.gov.au/networks-pipelines/compliance-reporting.

2019/20 Report

In the 2019/20 DMIS Annual Report, Gillieston Heights was reported both as a Committed Project and an Eligible Project. The air-conditioning load control solution was implemented in summer 2019/20. For further details, please refer to Ausgrid's 2019/20 DMIS Annual Report at https://www.aer.gov.au/networks-pipelines/compliance-reporting.

3.1.2 2020/21 demand management costs

Development and implementation costs for the Gillieston Heights project were $16,729 in opex in 2020/21. These costs included $1,573 in external contracted services, $4,741 in customer incentives and $10,416 in internal labour and overhead for customer acquisition, dispatch operations and payment of customer incentives.

These costs exclude the potential Retailer supplied grid-based battery support that was described in Ausgrid's 2019/20 DMIS Annual Report and was anticipated for summer 2020/21 but did not eventuate.

3.1.3 Summer 2020/21 implementation

The summer 2020/21 implementation comprised of ACLC and retailer Behavioural Demand Response (BDR) components only. For the ACLC component, the Demand Response Mode 2 was used, which caps the electrical input load for air-conditioning units to 50%.

3.1.3.1 Volume of demand management delivered – air conditioning load control (ACLC)

Measurement of the ACLC demand and energy reductions achieved by the Gillieston Heights demand management project was determined using a "day-matching" method whereby a day with similar weather to each dispatch day was identified using weather station data. For Gillieston, the weather data from the nearby

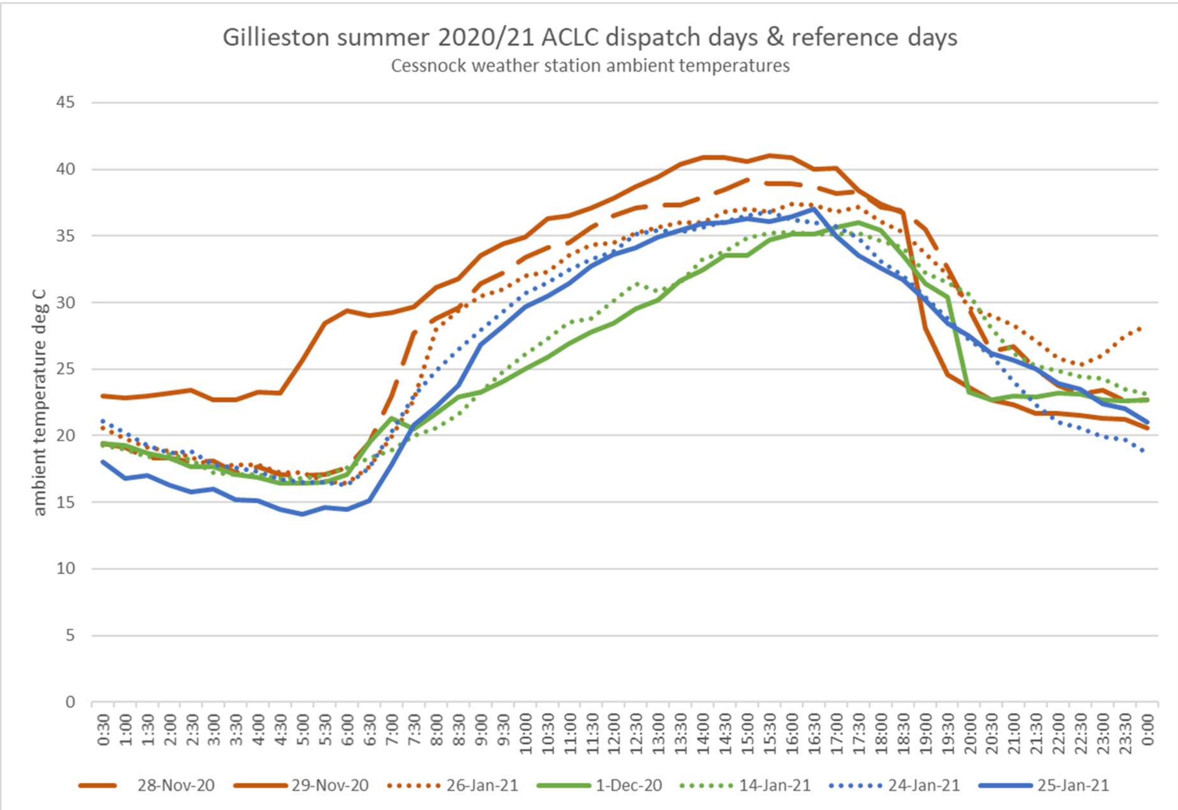
Cessnock weather station was used. Table 1 shows a comparison of each dispatch day with its selected reference day.

Table 1: Comparison of dispatch day and reference day temperatures

Dispatch day	Reference day	Dispatch day		Reference day	
		max temperature °C	avg temperature °C	max temperature °C	avg temperature °C
28 Nov 2020	26 Jan 2021	39.2	28.5	37.4	28.1
29 Nov 2020	26 Jan 2021	41	30.4	37.4	28.1
1 Dec 2020	14 Jan 2021	36	25.1	35.3	25.7
25 Jan 2021	26 Jan 2021	37	25.7	37.4	28.1

Temperature profiles for these days are shown in Figure 1 below. Dispatch days are colour-grouped with their selected reference days per Table 1 above.

Figure 1: Daily temperature profiles of dispatch days and reference days



Based on the selected reference day, average peak demand reductions are then calculated for each dispatch day within the dispatch window of 4-9pm AEDT based on analysis of half-hourly NMI energy consumption data (primary grid supply tariff) converted to kW. The kW for each half-hourly interval is therefore the average kW per half-hour.

Only those customers with interval metering can be considered and to further simplify the comparison, only customers without solar power systems are analysed. This is because solar customers with net metering have grid supply demand profiles that do not fully reflect their underlying customer demand.

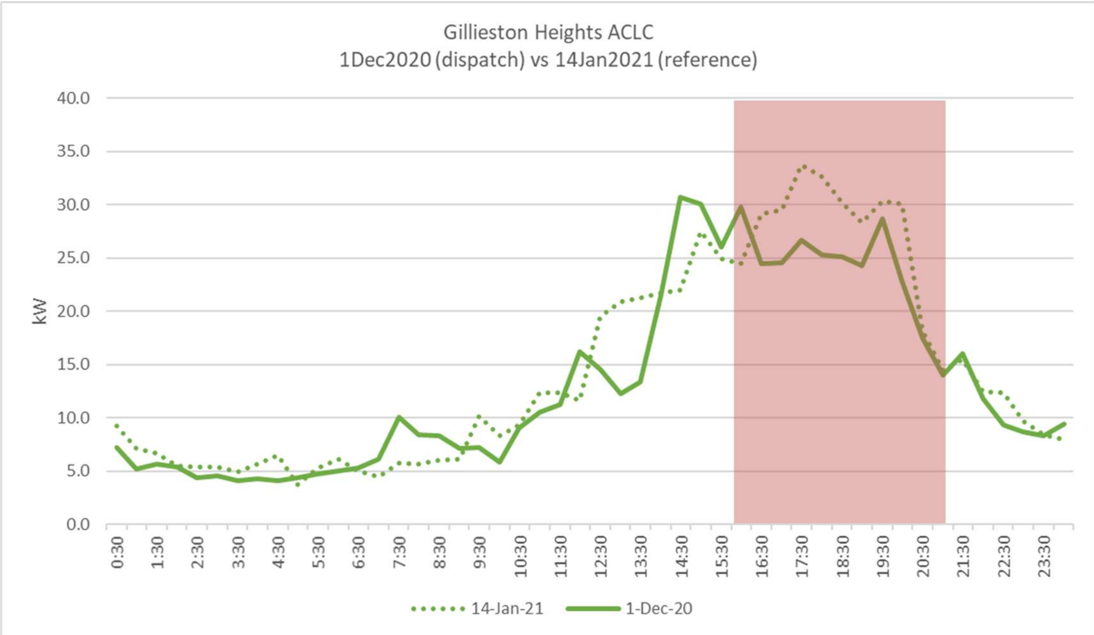
While modelling assumptions can be made to “add back” an estimated solar generation profile, it is subject to factors such as accurate recording of customer solar panel capacity and physical factors that affect real-time generation such as panel orientation, local cloud cover, panel degradation etc. It was considered that any errors in modelling these assumptions might swamp the ability to detect demand reductions, which led to the assessment that only interval-metered customers without solar would be included for analysis. Results from this subset can be extrapolated to the entire population of participants, some of whom may not have interval metering and may have solar systems.

As a result, there are 12 customers who do not have solar and who have interval metering out of the total cohort of 34 participating customers. For these 12 customers, analysis is carried out on the aggregated half-hourly profiles to smooth out individual customer variability. Comparison charts for the dispatch days 25 Jan 2021, 1 Dec 2020, 28 Nov 2020 and 29 Nov 2020 are shown below overlaid with their respective reference days in Figures 2, 3 and 4. The individual customer load profiles that form part of this set of 12 customers are metered at the point of grid supply, which means other household loads will be represented in the profile. This introduces additional variability in the comparisons.

The dispatch days of 1 Dec 2020 and 25 Jan 2021 shown in Figures 2 and 3 below. A visible reduction in aggregate customer demand compared to their respective reference baseline days can be seen during the dispatch window. The indicative average peak demand reduction on 1 Dec 2020 is about 0.6kW per customer and on 25 Jan 2021 is about 0.9kW per customer.

For the 1 Dec 2020 dispatch event, the maximum and average temperatures for the reference day are within 2% for that on the dispatch day. The similar demand profiles for the test group outside of the dispatch window would indicate that the day matching approach and reference day are reasonable.

Figure 2: Comparison of 1 Dec 2020 (dispatch day) vs 14 Jan 2021 (reference)



For the 25 Jan 2021 dispatch event, the maximum and average temperatures for the reference day are within 1% and 8% respectively of the dispatch day. The similar demand profiles for the test group outside of the dispatch window would indicate that the day matching approach and reference day are also appropriate.

Figure 3: Comparison of 25 Jan 2021 (dispatch day) vs 24 Jan 2021 (reference)

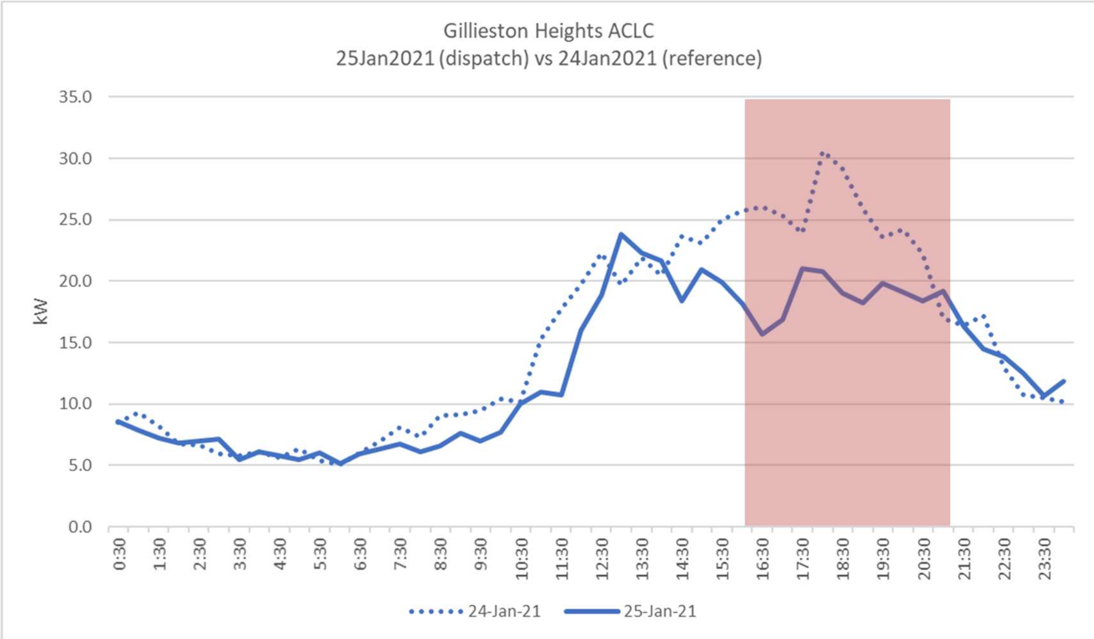
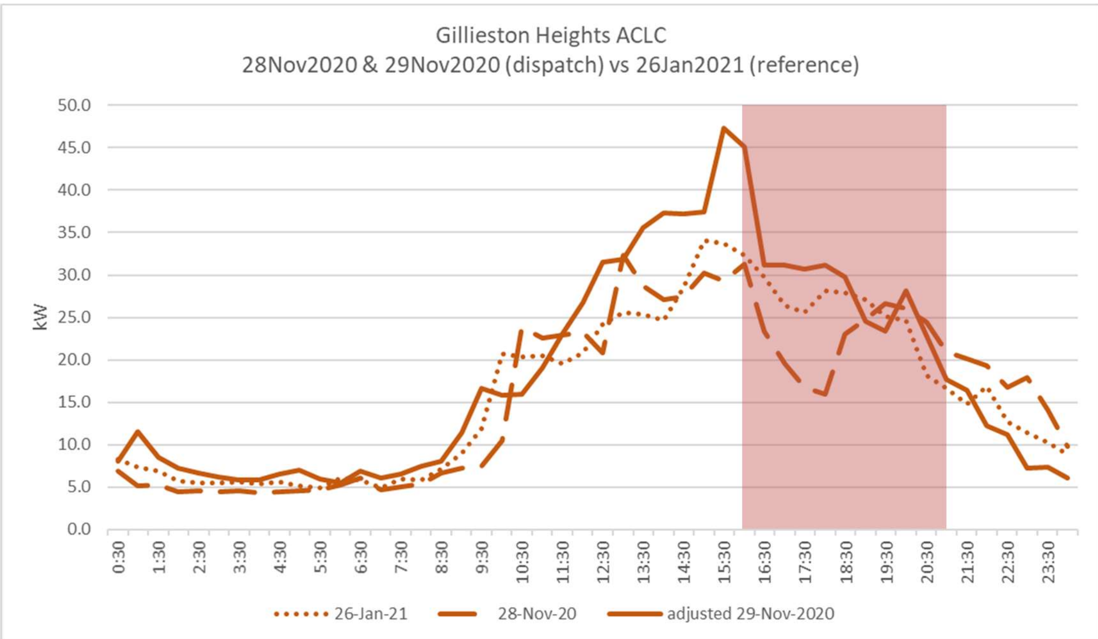


Figure 4 below shows the aggregated demand on dispatch days 28 Nov 2020 and 29 Nov 2020 compared to the reference day 26 Jan 2020. There is a visible demand reduction on 28 Nov during the dispatch window, with an average peak reduction of about 1.0kW per customer.

However, 29 Nov does not show a lower demand than the selected reference day with demand higher in the dispatch window compared to the reference day. The reason is likely due to 29 Nov being the hottest day in the summer period and that comparison with the selected reference day 26 Jan 2021 is not appropriate. Looking at the maximum and average temperatures for the dispatch day and the reference day in Table 1 above, maximum temperatures on the 29th Nov reached 41°C with an average daily temperature of 30.4°C. These maximum and average temperatures are 10% and 8% higher than the temperatures of 37.4°C and 28.1°C on the reference day. These results highlight the challenge of estimating demand response for residential customers using this method when similar baseline days are not available.

Figure 4: Comparison of 28, 29 Nov 2020 (dispatch days) vs 26 Jan 2021 (common reference)



One possible modified comparison would attempt to use the customer demand immediately prior to the dispatch event to adjust the comparison. For example, in Figure 5 below, where the demand profile of 29 Nov 2020 has been shifted down based on the average of the four half-hourly intervals prior to the commencement of dispatch, namely, the 2:00pm to 4:00pm period (dispatch commences at 4pm). Average demand in this period is 32kW on the reference day 26 Jan 2021 and 42kW on 29 Nov 2020, leading to an adjustment of 10kW (decrease) for 29 Nov. In Figure 5, the adjusted profile of 29 Nov is shown only for time periods around the dispatch window to avoid having to scale the adjustment for other times far from the dispatch window. Figure 5 shows this might be a reasonable method for accounting for the temperature difference between 29 Nov and the reference day. The calculated average demand saving is around 1.0kW per customer following the adjustment. This is roughly in line with results for other days indicating that this adjustment method has merit.

Figure 5: Comparison of adjusted 29 Nov 2020 (dispatch day) vs 26 Jan 2021 (reference)

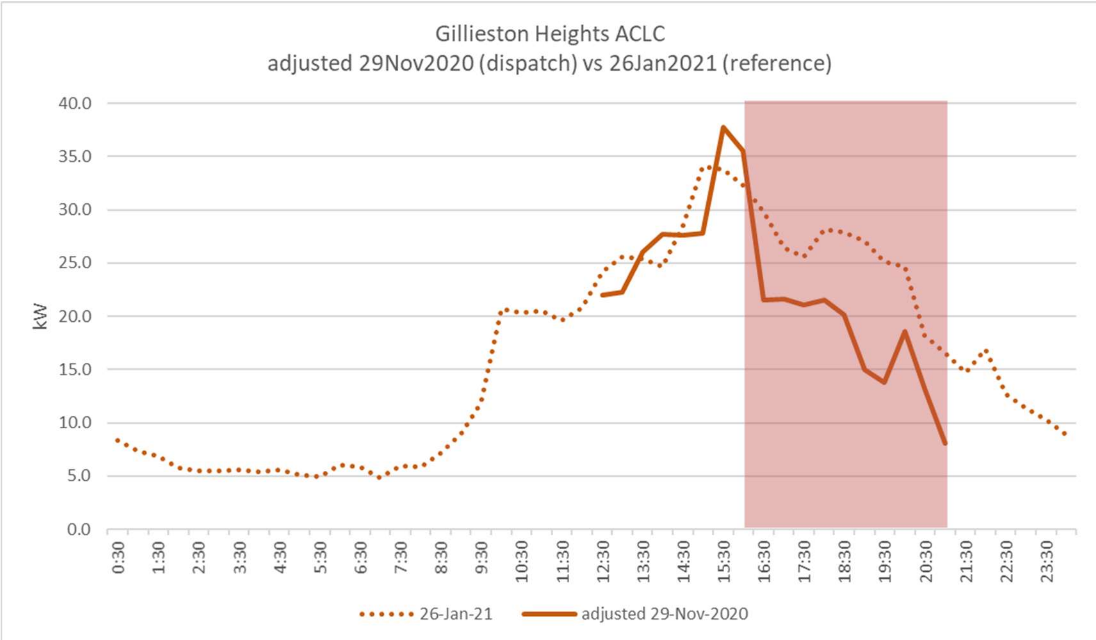


Table 2 below summarises the results of the dispatch day analysis above, showing average demand reduction ranging from 0.6 to 1.0 kW per customer.

Table 2: Summary of ACLC dispatch days

Dispatch day	Time	Demand profile adjustment	Number of customers analysed	Average demand reduction per customer (kW)
28 Nov 2020	4:00pm to 9:00pm	No	12	1.0
29 Nov 2020	4:00pm to 9:00pm	Yes	12	1.0
1 Dec 2020	4:00pm to 9:00pm	No	12	0.6
25 Jan 2021	4:00pm to 9:00pm	No	12	0.9

As maximum demand for the season occurred on the 29th Nov, the average demand reduction on this day is estimated to be the peak day demand reduction. Extrapolating these results to all 34 participating ACLC customers gives a total demand reduction of 34kW for the ACLC component of the Gillieston Heights demand management project.

3.1.4 Comparison with CoolSaver trial results

Figure 6 below shows the results obtained from the ACLC program run as part of Ausgrid's Coolsaver trial[1]. One key difference was that during Coolsaver, the air-conditioning load for participating customers was monitored directly, meaning that measurements were not confounded with other household loads, as is the case with the Gillieston Heights program, shown in Figures 2, 3, 4 and 5 above. The Coolsaver trial used the same method of signalling customer A/C units, so comparing the Gillieston Heights results against Coolsaver is reasonable noting the difference in point-of-measurement mentioned above.

The blue line in Figure 6 shows a clear reduction of around 1.5kW per customer under the Australian Standard AS4755 Demand Response 2 (DRM2) mode for customers with A/C cooling capacity over 10kW during the period of dispatch. This is higher than the results shown in Table 2 above where demand reductions were estimated to be about 0.6-1.0kW per customer.

Possible reasons for the lower results from the Gillieston Heights project include errors introduced when selecting the reference day (matched weather day) shown in Figures 2, 3, 4 and 5 above and changes in the demand from other appliances in the home. Further work is required to refine and develop higher confidence in the measurement and verification of demand reductions from demand response programs.

Figure 6: Coolsaver trial ACLC results (Figure 5 of Coolsaver report)

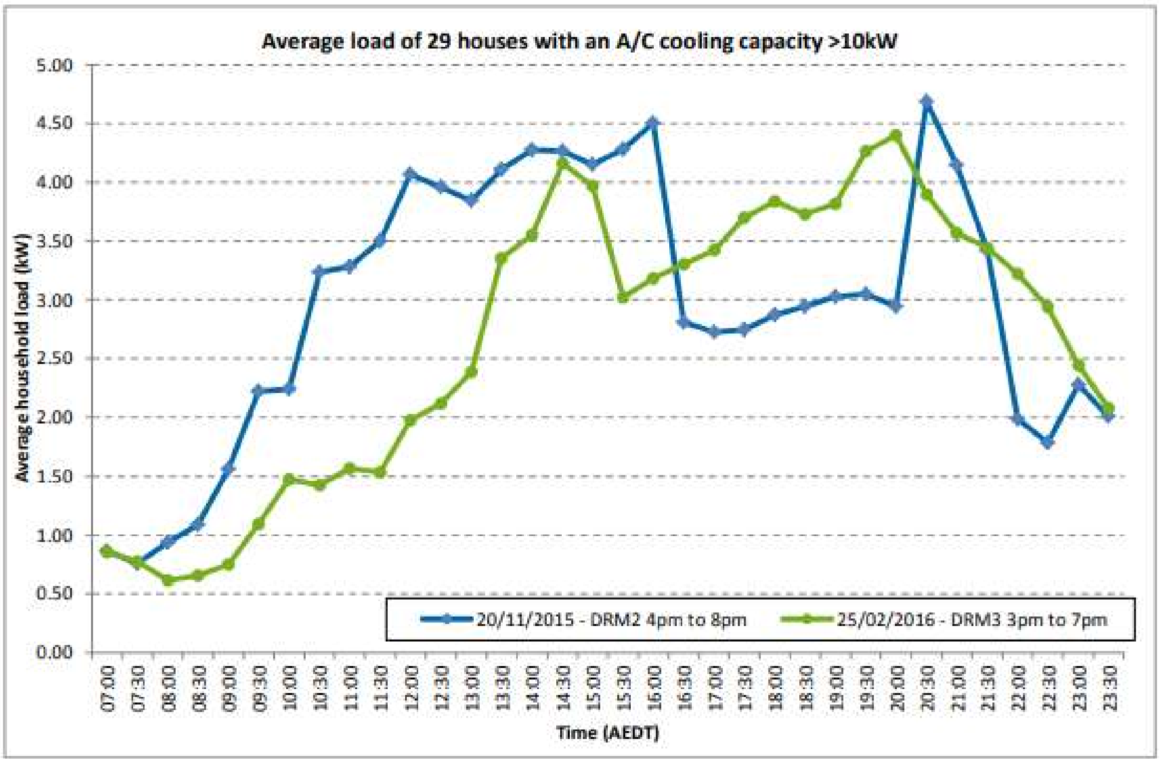


Figure 5 – Summer peak dispatch events

3.1.4.1 Volume of demand management delivered – behavioural demand response (BDR)

The behavioural demand response (BDR) component of the Gillieston Heights demand management project leverages partnerships with energy retailers to provide demand reductions. The customers who form part of

[1] https://www.ausgrid.com.au/-/media/Documents/Demand-Mgmt/DMIA-research/Ausgrid-CoolSaver-Interim-Report-2017_Final.pdf

the BDR component are part of a larger population of customers across Ausgrid's network who are participating in Ausgrid's Peak Time Rebate demand management innovation trial program.

The Peak Time Rebate demand management innovation program is being reported separately in Ausgrid's DMIA Annual Report. Costs and benefits for the Gillieston Heights aspects are separated from the DMIA and form part of the DMIS claim. Two retailers were involved during summer 2020/21.

Table 3 below provides details of the three (3) dispatch events conducted by RETAILER1 during summer 2020/21 as part of the Gillieston Heights demand management program. Table 3 is based on data provided by RETAILER1, including their own method of determining energy savings which was carried out on a per-customer basis.

All events were 3 hours in duration with commencement times ranging between 4:00pm and 5:00pm. Due to RETAILER1's use of an opt-out approach, Ausgrid considered that customers who did not show any reductions were not truly participating in the events and were therefore excluded. This meant that the number of participating customers ranged from 51 to 63 customers and achieved total demand reductions of between 51kW and 73kW across the 3 events. Average reductions of 1.0 to 1.4 kW per customer were estimated to have been achieved.

Table 3: RETAILER1 BDR event days – Gillieston Heights area

Date	Time	Duration (hrs)	Participant reduction (kW)	Participating customers	Total customers	Reduction per participating customer (kW)
14 Jan 2021	5:00pm to 8:00pm	3	51	51	136	1.0
25 Jan 2021	4:00pm to 7:00pm	3	64	64	141	1.0
26 Jan 2021	5:00pm to 8:00pm	3	73	53	140	1.4

Table 4 below provides details of the four (4) dispatch events carried out by RETAILER2 during summer 2020/21 as part of the Gillieston Heights demand management program. Table 4 is based on data provided by RETAILER2.

Events ranged from 2 to 3 hours duration with commencement times from 2:00pm to 5:00pm. Since RETAILER2 used an opt-in approach, it is assumed that all customers in the list provided by RETAILER2 are participating in the events. Across the 4 events, participation ranged between 7 to 11 customers relevant to the Gillieston Heights catchment with reductions ranging between 0.4 and 2.0 kW per customer.

Table 4: RETAILER2 BDR event days – Gillieston Heights area

Date	Time	Duration (hrs)	Participant reduction (kW)	Participating customers	Reduction per participating customer (kW)
22 Jan 2021	2:00pm to 4:00pm	2	14	7	2.0
25 Jan 2021	4:00pm to 7:00pm	3	5	9	0.6
12 Feb 2021	5:00pm to 7:00pm	2	5	8	0.6
1 Mar 2021	4:30pm to 6:30pm	2	4	11	0.4

Table 5 below summarises the demand reductions achieved across all components. Reductions ranged from 4kW to 99kW depending on the day and whether there were ACLC and/or retailer BDR events. The maximum peak demand reduction of 99kW occurred on 25 Jan 2021.

Table 5: Summary of ACLC and BDR events

Date	Component	Time	Reduction (kW)	Total daily reduction (kW)
28 Nov 2020	ACLC	4:00pm to 9:00pm	34	34
29 Nov 2020	ACLC	4:00pm to 9:00pm	34	34
1 Dec 2020	ACLC	4:00pm to 9:00pm	20	20
14 Jan 2021	RETAILER1	5:00pm to 8:00pm	51	51
22 Jan 2021	RETAILER2	2:00pm to 4:00pm	14	14
25 Jan 2021	RETAILER1	4:00pm to 7:00pm	64	99 (1 customer is part of ACLC and BDR)
	RETAILER2	4:00pm to 7:00pm	5	
	ACLC	4:00pm to 9:00pm	31	
26 Jan 2021	RETAILER1	5:00pm to 8:00pm	73	73
12 Feb 2021	RETAILER2	5:00pm to 7:00pm	5	5
1 Mar 2021	RETAILER2	4:30pm to 6:30pm	4	4

Peak demand events were relatively few throughout summer 2020/21 and so there is not a consistent pattern of ACLC and BDR events occurring on the same days. Note there were contractual limitations in place which imposed some restrictions on Ausgrid's discretion with dispatch events.

3.1.5 Estimate of realised benefits

Per the volume of demand reduction capability delivered noted in 3.1.3 above and the cost benefit assessment for the project deferral, the realised benefits of the demand management option are estimated to be about $0.37 million present value. This total includes actual or estimated values for:

- Benefits delivered by the DM program including option value;
- Benefits delivered by the network solution deferred by one year;
- Residual value of the network solution at the end of analysis period;
- Cost of the network solution deferred by one year; and
- Cost of the DM program.

3.1.6 Claimed incentive

Applying Equation 1:

$$PV\ incentive_i \leq \max\{dv \times E\ [PV\ DMcost_i - S_i]\ ,0\}$$

Subject to the constraint:

$$d_v \times E[PV\ DMcost_i] \leq E[NPV_i]$$

where:

- Subscript i means the parameter concerns committed project i.
- PV is the present value at time t. A parameter following PV is in real dollars at time t

- $incentive_i$ is the project incentive for each project i.
- max {.} means the higher of the values within the brackets that are separated by commas.
- Si is the total subsidies provided to the distributor in connection with providing the demand management component of project i.
- E[.] denotes an expected value, which has been calculated when project i became a committed project.
- D$Mcost_i$ is project i's demand management costs.
- NPV_i is the expected relevant net benefit of committed project i.
- d_v=d_1=50%

The expected project costs when the project became a committed project were $17,000.

The expected total subsidies when the project became a committed project were $0.

Therefore, per equation 1, $PV\ incentive_i$ = max (0.5 x $17,000 - 0) = $8,500

The expected relevant net benefit was $0.37m.

Therefore, the constraint is satisfied as the calculated incentive of $8,500 is below the expected net benefit of $0.37m. The claimed incentive is also below the 1% of Ausgrid's annual smoothed revenue requirement.

Note that actual costs in 2019/20 were slightly lower than estimated with actual costs of $16,729. The net benefit calculation at these costs is approximately the same.

3.1.7 Accruing of project incentives

In accordance with Section 2.5 of the DMIS Guidelines Dec 2017, Ausgrid proposes that the following table should summarise the incentives and accruals of committed projects. Amounts for 2019/20 are taken from Ausgrid's 2019/20 DMIS Annual Report:

Table 6: Accrual of project incentives

Description	2019/20	2020/21	2021/22	2022/23	2023/24
Gillieston Heights accrued incentive	$27,500	$8,500			
Total incentive accrued to projects	$27,500	$8,500			
1% AR cap[2]	$14,468,000	$14,463,000			
Total accrued (up to cap)	$27,500	$8,500			
Incentive to be paid (2-year lag)			$27,500	$8,500	

[2]https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Ausgrid%20distribution%20determination%202019-24%20-%20Attachment%201%20-%20Annual%20revenue%20requirement%20-%20April%202019.pdf

4 PART B – Eligible Projects

4.1 Gillieston Heights demand management project

4.1.1 Description of need

Following the demand reductions achieved in summer 2020/21, updated demand forecasts indicate the continued existence of a network need in summer 2021/22 and beyond, driven by continuing customer connections activity in the area.

Based on the assessment process described in 2.2.1, Ausgrid has determined that demand management is likely to again offer a cost-efficient deferral of the proposed preferred network solution by another year and therefore Ausgrid considers Gillieston Heights an Eligible Project for summer 2021/22.

4.1.2 Expected costs and benefits

The following table summarises the present value of expected costs and benefits determined using the process described in Section 2.2.1 of this report.

The figures in Table 7 below include a variation in the project scope compared to summer 2020/21. The types of demand reductions to be deployed in summer 2021/22 will include:

- An expanded demand response program driven by an increasing volume of customers participating in the existing retailer supplied demand response;
- The addition of a 3rd electricity retailer supplying customer demand response; and
- Ausgrid delivered air-conditioning load control as implemented in summer 2020/21 using the same number of customers. No further expansion of ACLC customers will be undertaken.

Table 7: Expected costs and benefits

Option	Deferral period	PV of Benefits ($m)	PV of Costs ($m)	NPV ($m)
network option	-	1.07	-0.73	0.33
DM	1 year	1.08	-0.74	0.33

Ausgrid considers that the 1-year deferral option and the network option are equivalent in NPV terms and consequently selects the demand management option as the preferred option.

Due to uncertainties around the future growth in new local customer connections, customer adoption of smart meters and customer take-up of Retailer led demand response solutions, Ausgrid has elected not to assess demand management deferral beyond the first year. A review post-summer 2021/22 will be undertaken to assess whether further demand management opportunities exist using latest available information.

4.1.3 Demand management proposal

Ausgrid intends to proceed with the deferral of the proposed supply solution at Gillieston Heights as a **demand management proposal** which is summarised in Section 4.1.4 below.

As described in the Ausgrid's 2018/19 DMIS annual report, a request for **demand management proposals** was issued in 2019 which yielded no viable market-led solutions.

The air-conditioning load control method will again be deployed. Retailer supplied network support from behavioural and automated customer demand response will provide additional demand reductions to address load at risk in the affected network area.

4.1.4 Ausgrid proposal

Table 8: Ausgrid proposal of blended ACLC and retailer supplied BDR for summer 2021/22

Proposal No.	1
Description	Blended solution including: • Air-conditioning (AC) load control • Retailer supplied residential demand response
Deliverables	Demand reductions via: • AC load control using ripple control signals to DREDs installed on participating customer AC units • Retailer supplied residential demand response
Expected cost	$38,640
Assessment	Cost-benefit assessment indicates solution is economically feasible to reduce the load at risk on the relevant 11kV feeders in summer 2020/21. Expected NPV = $0.33 million. Deferral beyond summer 2021/22 will be considered post-summer.

4.1.5 Preferred option

On the basis that the Ausgrid proposal for a 1-year deferral offers an equivalent NPV to the network option as shown in Table 2 above, Ausgrid considers it to be an efficient solution. Due to the reasons given in section 4.1.3, Ausgrid has decided to proceed with the demand management project as a **demand management proposal**.

As noted above, the expected cost for the demand management is $38,640.

Further deferral may be possible, contingent upon re-assessment of the benefits and costs post-summer 2021/22.

4.1.6 Amount of demand reductions

The target demand reduction in summer 2021/22 is estimated at 525 kVA.

5 Demand Management Projects That Have Changed

In accordance with 2.4 (6) and (7) of the DMIS, this section describes projects where Ausgrid has decided to either:

- Defer or not proceed with an eligible project that it had previously decided (either in 2020/21 or in previous years) to proceed with as a **committed** (demand management) **project**; OR
- Proceed with a network option to meet an identified need that it had previously decided to meet by means of a project that was a **committed** (demand management) **project**.

5.1 Previously committed DM projects now deferred or not proceeding

None.

5.2 Previously committed DM projects now superseded by network option

None.