Demand Management Incentive Scheme Compliance Report – H1 2021

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Contents

1 Introduction

The AER published a new Demand Management Incentive Scheme (DMIS) in 2017 to encourage distribution businesses to adopt lower-cost non-network solutions, rather than investing solely in network solutions. The scheme provides incentive payments up to 50% of the expected costs on efficient demand management projects. United Energy (UE) applied for early application of the scheme from 2019 and this was approved by the AER. This compliance report has been prepared in accordance with the requirements in section 2.4 of the scheme.

As per section 2.4 (3) of the scheme this compliance report includes two parts:

- Part A includes information on committed projects.
- Part B contains information on projects that the distributor has identified as eligible projects.

This DMIS compliance report relates to the period 1 January 2021 to 30 June 2021 (HY 2021) reporting period.

In H1 2021 UE has continued demand management for two of its committed projects with already claimed DMIS incentive payments and as reported in previous DMIS compliance reports.

- UE Summer Saver Demand Management Program 2020/21 (SSP 21); and
- UE and Aggreko Lower Mornington Peninsula Demand Management Solution.

In H1 2021, UE identified one new eligible project which it also committed to under the DMIS scheme as detailed below:

- UE Summer Saver Demand Management Program 2021/22 (SSP 22).

Summer Saver Demand Management Solution 2021/22

The purpose of Summer Saver Demand Management Program is to defer capital expenditure on UE's Distribution System Augmentation Program (known as 'DSS'). The DSS is undertaken to augment overloaded distribution substations and low-voltage circuits to maintain reliability of supply. Summer Saver is implemented in place of the DSS to achieve the same outcomes for customers, but at a lower cost than the DSS.

We can confirm that the 2021/22 Summer Saver Program is not funded by any other sources and has not had expenditure committed to it before the first application of this scheme on 1 November 2019. The summer saver non network solution is assessed annually against network augmentation (DSS program) and other non-network proposals we receive from non-network service providers via a tender process.

The decision on whether to initiate and commit to a summer saver project is made annually and independently of the previous year's project commitment. UE considers an annual approach allows for the most appropriate summer saver scheme design. A review prior to initiating and committing to the project ensures UE can economically re-evaluate the most appropriate DSS sites for inclusion, select the efficient amount of demand management based on the most recent demand forecasts, and select the most efficient partner through a tender process year on year. No budget is committed to summer saver unless it is assessed as the most technically and financially suitable option.

In H1 2021, UE engaged with the broader market for consultation by undertaking a request-for-proposals from non-network service providers to provide lower-cost alternative solutions to resolve identified low-voltage network constraints. In response to this consultation, UE received five proposals being the Summer Saver demand management program and four proposals from alternative parties GreenBe, Zen, DNA and Enlightened Group. The Summer Saver Program and GreenBe were determined to be the only credible options for a demand response program that would defer the proposed DSS augmentation program. Although GreenBe solution was technically feasible it was found to be higher cost than Summer Saver, resulting in lower NPV.

The Summer Saver demand management program was identified as the preferred least-cost solution to address the low-voltage constraints and is to be deployed to 234 network-constrained sites as an alternative to DSS augmentation for summer 2021/22. The total approved cost of the Summer Saver Program for these 234 sites for summer 2021/22 is $337,894. Based on the DMIS, UE is eligible for the full 50% incentive of the demand management costs under the scheme of $337,894 * 50% = $168,947.

2 Part A - Committed Projects

UE identified and committed to one new eligible project and continued two previously committed projects under the DMIS during H1 2021:

- UE Summer Saver Demand Management Program 2021/22;
- UE Summer Saver Demand Management Program 2020/21; and
- UE and Aggreko Lower Mornington Peninsula Demand Management Solution.

During H1 2021, UE completed the 2020/21 Summer Saver Demand Management Program which was a committed project in 2020 as per the 2020 DMIS Compliance Report.

This section outlines the required compliance information for these programs during H1 2021 as required under section 2.4(4) of the DMIS.

2.1 Summer Saver Program 2020/21 (SSP21)

The Summer Saver Program 2020/21 (SSP21) was deployed to 214 network constrained sites, supplying approximately 20,474 customers during 2020/21 summer with two demand management events called during H1 2021. A summary of the demand management delivered for the event, as required under DMIS clause 2.4(4)(a), is shown in Table 1. The event performance data has been attached in Appendix 4 (Section 4.4).

Table 1 : Summer Saver 2020/21 (SSP21) event summary (H1 2021)

	Event 1	Event 2
Date of event	11/01/2021	25/01/2021
Average Demand Reduction per Hour (kW)	1.0	1.6
Total Demand Reduction (MW)	1.1	2.1
Number of Participants	1,142	1,300
Reward per Participant	$25	$37

The benefits of the Summer Saver 2020/21 program (SSP21) in H1 2021, as required under DMIS clause 2.4(4)(b), are:

- Avoiding customer outages for 20,474 customers in the affected areas.
- An estimated expected unserved energy reduction of $352k, using the value of customer reliability (VCR), for the two H1 2021 events.[1]
- Deferral of $11.8M of DSS augmentation capex ($2020).

The total financial incentive for this committed project under DMIS clause 2.4(4)(c) and in accordance with clauses 2.2, 2.3 and 2.5 of the scheme, was previously approved for the CY 2020 regulatory year.

[1] Based on a $2020 VCR of $21.25 per kWh.

2.2 Lower Mornington Peninsula Demand Management Program

The Lower Mornington Peninsula Demand Management Program was established for summer 2020/21 with 11MVA of Aggreko generation installed and commissioned in December across the 5 customer sites on the Lower Mornington Peninsula. No demand management events were called during H1 2021 due to mild summer weather conditions meaning the maximum demand conditions and voltage collapse threshold was not met.

The benefits of the program for H1 2021, as required under DMIS clause 2.4(4) (b), are:

- Deferral of $31.5M of augmentation capex for the establishment of a new 54km sub-transmission line from Hastings (HGS) to Rosebud (RBD) zone substations.
- The program addresses the voltage collapse risk which could lead to supply interruption to approximately 50,000 customers across the Mornington Peninsula.
- The avoided expected unserved energy due to the program for summer 2020/21 is $715k.

2.3 Summer Saver Program 2021/22 (SSP22)

The Summer Saver Program 2021/22 (SSP22) is currently being deployed to 234 low-voltage constrained sites, supplying approximately 19,066 customers. SSP22 events shall be dispatched from December 2021 to March 2022.

The selected low-voltage circuits were predominantly residential customers. The SSP22 summer saver sites are graphically shown in Figure 1.

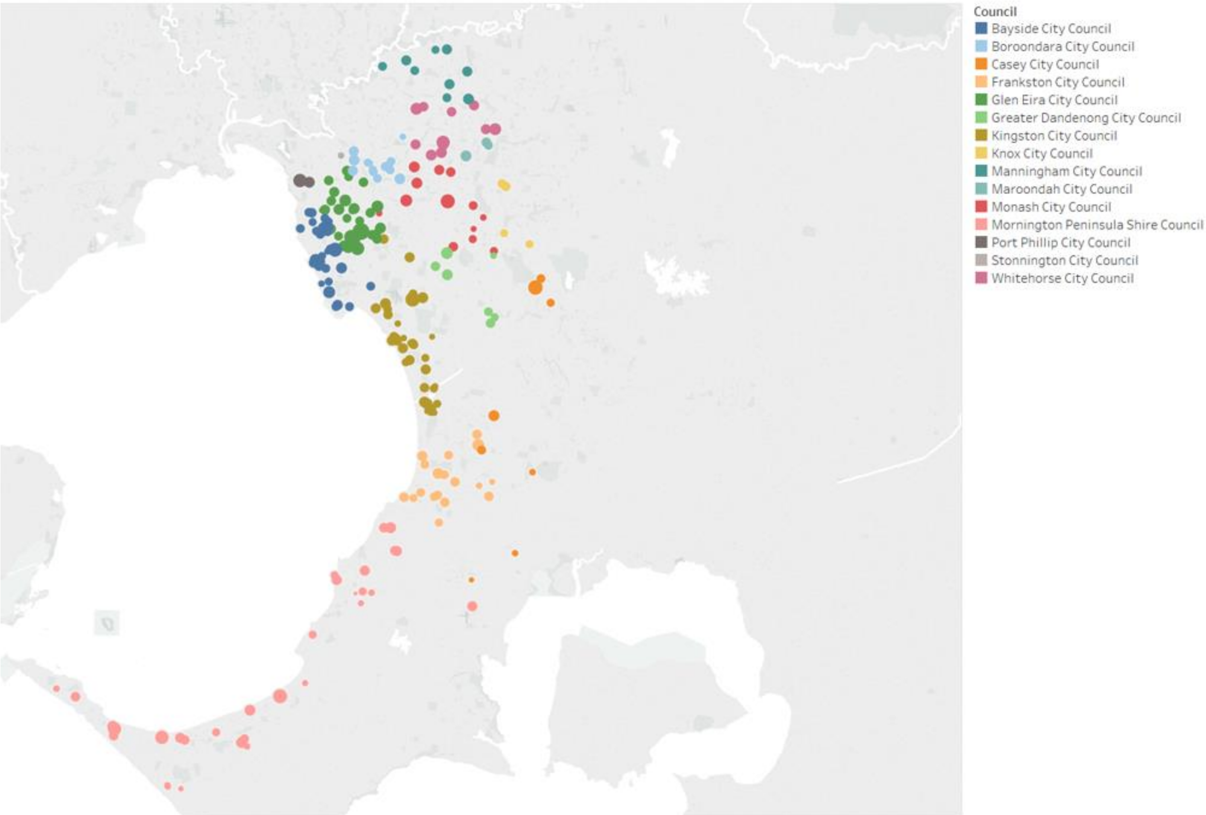


Figure 1 : Summer Saver 2021/22 selected sites

The benefits of the program for summer 2021/22, as required under DMIS clause 2.4(4) (b), are:

- The program addresses network constrains at the low-voltage circuits by avoiding expected outages for 19,066 customers.
- Deferral of $12.9M of DSS augmentation capex.
- The avoided expected unserved energy due to the program for summer 2021/22 is $841k.

As required under DMIS clause 2.4(4)(c), the total financial incentive that the distributor has assessed that it is able to claim for this committed project in accordance with clauses 2.2, 2.3 and 2.5 of this scheme, for the H1 2021 regulatory period is calculated as follows:

- Expected total present value of the demand management costs is $337.9k as detailed in Part B - [PV $DMcost$]) in Section 3.1.3.
- Expected net economic benefit of the project is $503k as detailed in Part B - [NPV] in Section 3.1.3.
- Since 50% * [$PV\ DMcost$] ≤ [NPV], UE are eligible for the full 50% incentive of the demand management costs of $337,894 * 50% = $168,947 under the scheme.

3 Part B - Eligible Projects

As described in Section 2, UE identified one eligible project under the new DMIS scheme in HY 2021 which also became committed:

- UE Summer Saver Demand Management Program 2021/22.

This section outlines the required compliance information for this eligible project during H1 2021 as required under section 2.4(4) of the DMIS.

3.1 Summer Saver Demand Management Program 2021/22

The Summer Saver Program 2021/22 (SSP22) was determined as an 'efficient non-network' option relating to demand management for the DSS augmentation program as required under the scheme. UE has met all the minimum project evaluation and eligibility criteria as per section 2.2 and 2.2.1 of the DMIS for an efficient project under the scheme, including a request for quotes via its Demand Side Engagement Register and undertaking a net present value (NPV) economic benefit assessment (or a consumer benefit assessment). The request for proposal has been attached in Appendix 1 (Section 4.1).

3.1.1 Proposals Overview

In response to a request for non-network proposals to address constraints in the low-voltage network during summer 2021/22, UE received five non-network proposals (four of which were from third parties). Two of the five proposals were considered to be credible, namely UE's Summer Saver Program and GreenBe's Demand Management Solution, to address the low-voltage circuit thermal constraints. Summary of these proposals are listed in the following sections.

3.1.1.1 Summer Saver Program

The Summer Saver Program is a behavioural demand response program that incentivises customers to reduce their power usage during times of maximum demand. The program targets constrained areas with highly utilised distribution transformers and low-voltage circuits that are at an elevated risk of overload outages during summer to defer network augmentation.

The Summer Saver Program utilises the capabilities of the Advanced Metering Infrastructure to encourage customer participation and engagement whilst lowering implementation costs.

Once registered, participants are requested to voluntarily reduce their power usage during a three-hour event window on a small number of hot weather 'event days' which typically are on weekdays over the summer period.

Customers are notified at least two days in advance of an 'event day' so they could plan how to reduce their energy consumption. Customers who successfully lower their energy consumption below their allocated baseline during the event are rewarded. SSP22 is based on a voluntary usage reduction program utilising high-frequency AMI data.

SSP22 includes the following features:

- Digital customer web and mobile enrollment
- Web and mobile utility customer portals
- Demand response management system
- Electronic Fund Transfer (EFT) after each event
- Pre-event tips and alerts
- Digital email/SMS engagement
- Customer reporting.

Figure 2 illustrates an overview of the SSP22 program. It describes the relationship between the operational components of the program and the interface between the technology system, program managers, and the participating household.

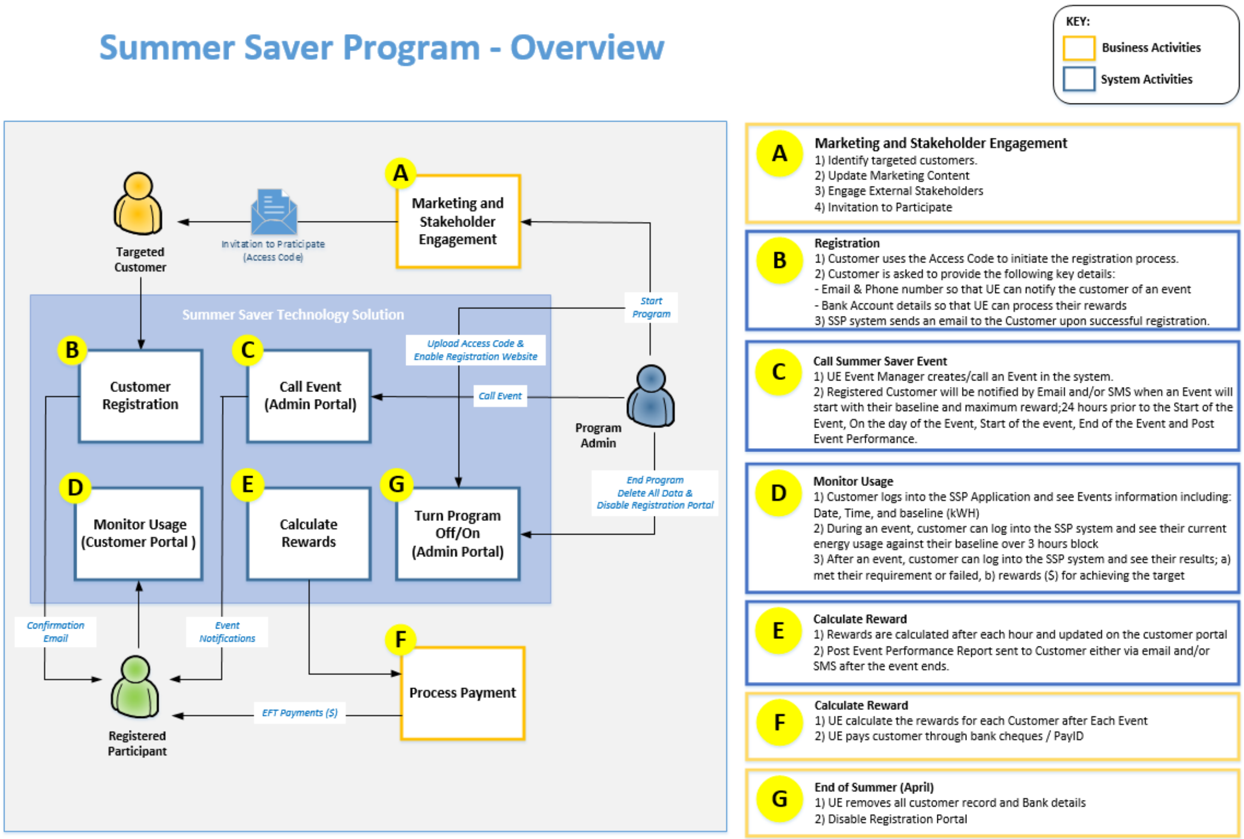
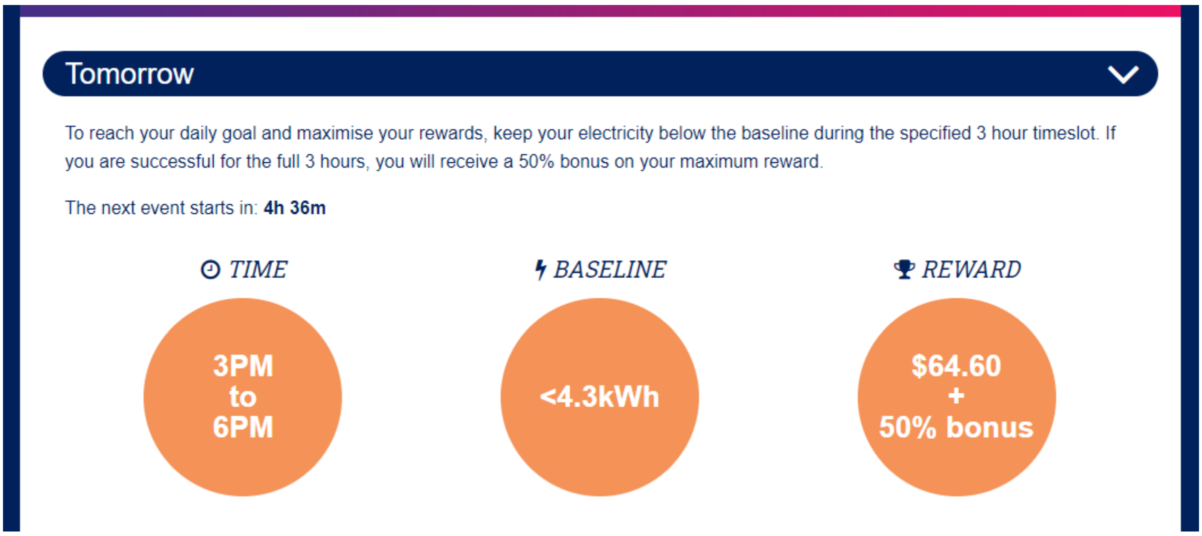


Figure 2 : Overview of Summer Saver Program 2021/22

Figure 3 and Figure 4 show the Summer Saver Program Customer Portal before, during and after a demand response event.



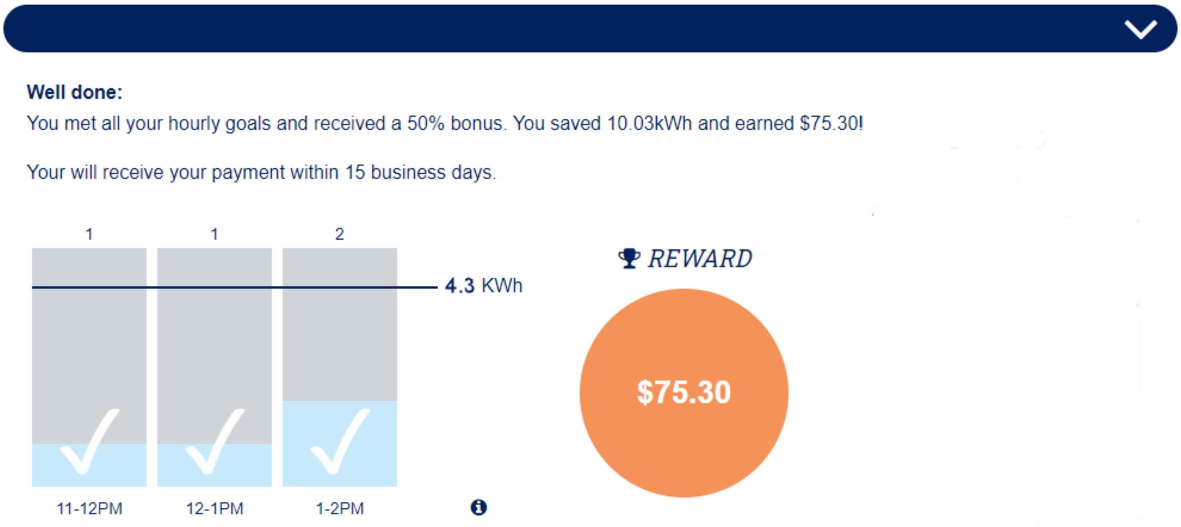


Figure 3 : Summer Saver Program customer portal before and after an event

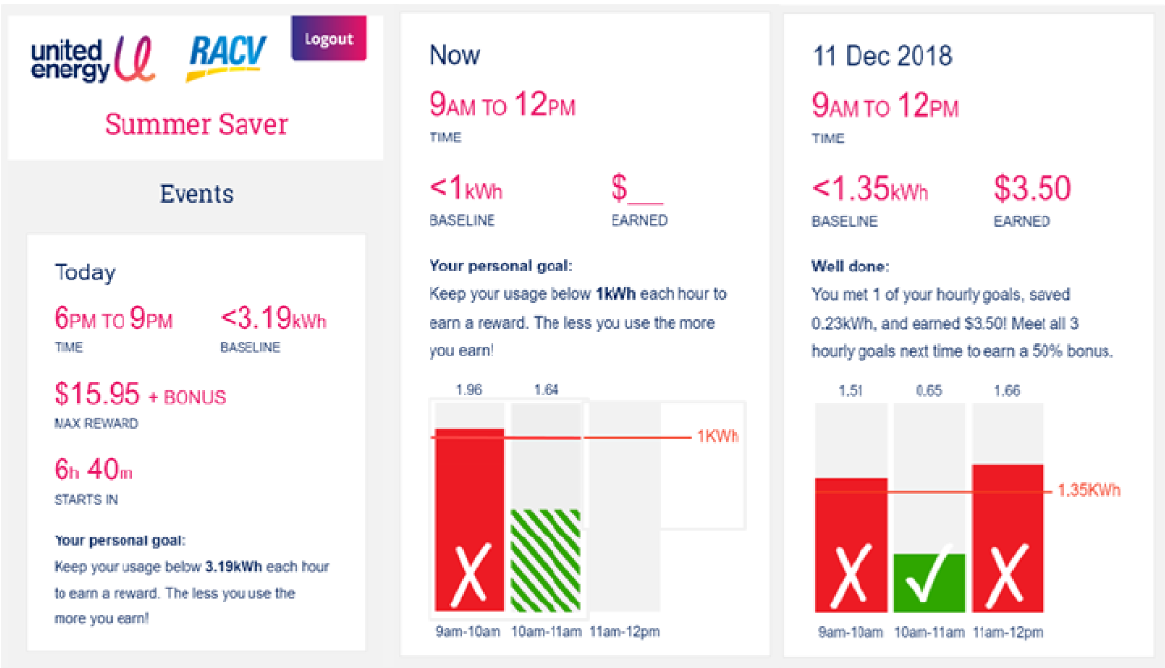


Figure 4 : Summer Saver Program Mobile Application before, during and after an event

3.1.1.2 GreenBe Proposal

GreenBe technology company offered a non-network residential behavioral demand management cloud platform and application - an alternative to the Summer Saver Program.

GreenBe proposal offered an end-to-end solution that included event dispatch, the provision of digital apps, marketing, recruitment and rewards incentive payments for customers within the constrained sites. The proposal included deploying their existing Digital Customer Engagement Portal apps with customisations made to brand elements and integration with UE's residential customer network consisting of the following features:

- Web and mobile utility customer portals
- Digital customer web and mobile enrollment
- Demand response management system
- Digital points and rewards engine
- Year round household energy challenges
- Pre-event tips and alerts
- Digital email engagement
- Customer relationship management portal and customer reporting.

Figure 5 illustrates an overview of GreenBe proposal.

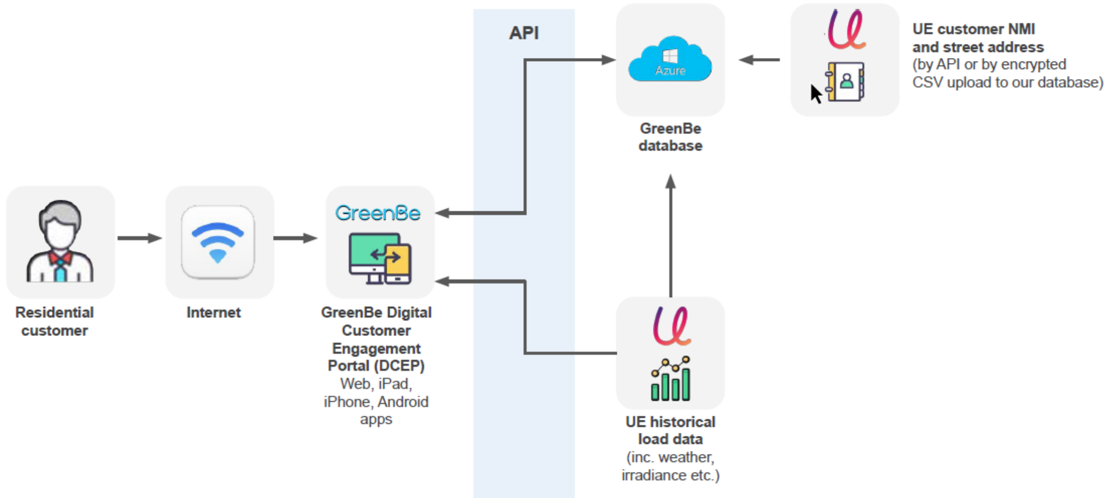


Figure 5: Overview of GreenBe proposal

According to GreenBe proposal:

Prior to a demand response event, residential customers are notified by email/app push and/or SMS alert of the upcoming challenge. Customers are asked to voluntarily opt-in to each demand response event via the app.

Once opted into the event, participants are coached on how to meet their energy saving target. Customers are able to view their individual household baseline reduction target and load intervals from within the app.

Customers successfully pass the DR challenge if their overall household usage is under their individual baseline target. Successful customers are then credited with points into their account to instantly redeem. Unsuccessful are invited to try again for the next energy challenge event.

Figure 6 shows the GreenBe Customer Portal before, during and after a demand response event.

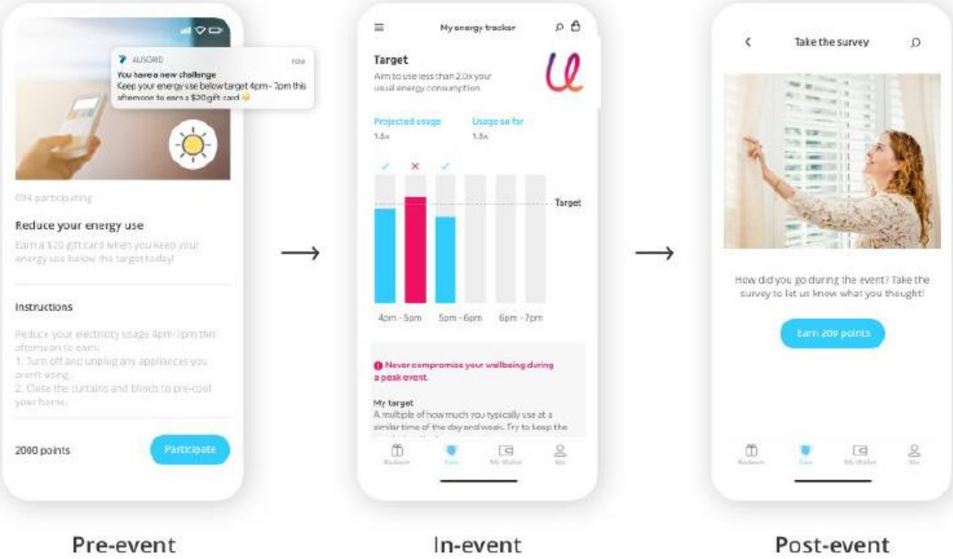


Figure 6 : GreenBe Customer Portal before, during and after an event

3.1.1.1 Zen Ecosystems

Zen Ecosystem offered a load control demand management program for 17 sites including retail outlets and supermarkets using Zen Ecosystem distributed energy management platform. None of the proposed sites were within the constraints areas and therefore, this proposal was considered to be technically not feasible.

3.1.1.2 DNA Energy

DNA Energy offered a load control demand management program described as demand response system capable of wirelessly controlling virtually any load (including Non AS4755 compliant). The system compromises of the following key components:

- Demand Control Signal Receiver (DCSR) installed at the premises and connected to the load being controlled. One DCSR unit per controlled load is required
- VPP control software and dashboard
- Reference gate meter
- IoT gateway to enable device to device or device to cloud communication.

This proposal was considered to be not credible as it did not provide details on how the solution would be developed including firm total costs. Instead the proposal focused on the concept of load control using the DCSR device. This proposal did not provide information on:

- The ability to deliver the program before December 2021.
- Calculation of baseline demand and measurements
- Method of interaction with customers pre-event, during event and post-event
- Firm costs (fixed and variable costs).

Given the above limitations, UE consulted DNA Energy to formalise above requirements. DNA Energy indicated they did not have the details required by UE at this stage. However, has indicated the willingness to provide above requirements in future proposals.

3.1.1.3 Enlightened Group

Enlightened Group offered a load control demand management program described as Networked Energy Demand – Behind the Meter (NED) solution.

Demand management solution provided by controlling the smart loads behind the meter using the NED device installed at the premises. Examples of load that can be controlled by NED include:

- Batteries
- Smart Hot water Systems
- Smart Air Conditioner
- Electric Vehicle

One NED device is required per premises and it can be self-installed.

Internet and WIFI connectivity are required for the NED device to function.

This proposal was considered to be not credible as it did not provide details on how the solution would be developed including firm total costs. Instead it focused on the concept of using the NED device to control residential smart loads. This proposal did not provide information on:

- The ability to deliver the program before December 2021.
- Calculation of baseline demand and measurements
- Method of interaction with customers pre-event, during event and post-event
- Firm costs (fixed and variable costs).

Based on the limited information, UE considered this option to be technically and economically unviable for the following reasons:

- The low uptake rate of 5% (as per proposal) is not sufficient to provide the demand reduction required in all constraints areas resulting in high residual risk

- No estimate for load reduction was provided, however the controllable load of 5kW per premises was proposed. It should be noted that this expected reduction is significantly higher than the calculated ADMD per premise within the constrained area during high demand periods

- Based on the proposal, the cost of NED device alone is $330 per device + $15/month subscription fee. In the absence of any other costs, this option is expected to be significantly more than other identified credible demand management solutions. For example the cost of setup and installation for 2,000 customers with 3 months subscription fee is $750,000 = ($330 + $15 x 3) x 2,000 which is a lot more than the total cost of summer saver program (approximately $300,000 per annum).

Given the above limitations, UE consulted Enlightened Group to formalise above requirements. Enlightened Group indicated they did not have the details required by UE at this stage. However, has indicated the willingness to provide above requirements in future proposals.

3.1.2 Expected Demand Management Proposal Costs

A summary of the cost estimate and customer participation assumptions underpinning the credible options are summarised in Table 2. The customer payouts have been estimated based on the previous several years' experience including the estimated programs costs and customer participation rates. The costing is also based on incurring customer payments for four summer saver demand management events (the historical average).

Table 2 : Summer Saver cost and customer participation assumptions

Item	Summer Saver
Expected Take Up Rate	15.0%
Payment per kWh	$7.50
Hours per event	3
Event success rate	80%
Reduction per customer (kW)	1.5
Events per Summer	4
Acquisition Cost per Customer	$23.17[2]

The total customer base to be targeted over the 234 economic SSP sites is 19,066 customers. The summary of the estimated costs for the entire program is provide in Table 3.

Table 3 : 2021/22 Summer Saver cost estimate for 234 sites

Item	Summer Saver
Total Cost per year	$ 337,894

Being an internal UE-led demand management proposal, to meet the committed project requirements, a declaration was required to approve the proposal and to demonstrate that its cost estimation was reasonable[3]. This declaration is provided in Appendix 2 (Section 4.2) which includes the cost comparison of the Summer Saver and GreenBe programs across the 234 sites. The cost comparison summary is provided in Table 4.

[2] Acquisition Cost per Customer is the estimated Marketing Cost required to recruit and register one Summer Saver participant. This figure is estimated based on the historical marketing cost and the registered participants of the Summer Saver Program over the last 3 years.
[3] Australian Energy Regulator, Demand Management Incentive Scheme – Electricity network service providers, December 17, cl. 2.2.2(1)(b).

Table 4 : 2021/22 Expected cost of proposals for 234 sites[4]

Item	Summer Saver	GreenBe Yr1	GreenBe Yr1+
Total Cost per year	$ 337,894	$ 470,764	$ 421,820
Cost per customer	$131	$183	$164
Demand Reduction delivered (kVA)	3,091	3,091	3,091
Cost per kVA delivered	$109	$152	$136

3.1.3 Net Market Benefit Assessment

Four options were assessed to address the identified need for the DSS sites as below:

- Do Nothing – Status quo (reference case)
- Option 1 – Distribution Substation or LV circuit Augmentation (DSS)
- Option 2 – Summer Saver Demand Management Program
- Option 3 – GreenBe Demand Management Program.

The NPV assessment of the net economic benefits is presented relative to the 'do-nothing' scenario over a 20-year assessment period (to enable a comparison with the capital solution) using a real discount rate of 2.66%. The benefits are based on the reduced expected unserved energy, valued at the value of customer reliability[5], from avoiding outages in the peak loading periods. A summary of the net economic benefits of each option for the 234 sites is summarised in Table 5.

Table 5 : Summary of net economic benefits ($k, 2021)

Option	Description	Present value costs	Present value benefits	Net economic benefits	Rank
Do-nothing	Maintain the status-quo	-	-	-	4
1	Distribution Substation and LV circuit Augmentation (DSS)	-$12,870	$18,532	$5,662	3
2	Summer Saver Demand Management	-$5,326	$13,248	$7,923	1
3	GreenBe Demand Management	-$6,612	$13,248	$6,636	2

As illustrated in Table 5, the preferred option (which maximises the net economic benefits) was option 2 – undertaking the Summer Saver program. Due to its higher costs, the GreenBe solution was identified to be uneconomic. Refer to Appendix 3 (Section 4.3) for market assessment model.

UE reassesses and recommits to addressing low-voltage network constraints annually which also provides option value over the augmentation option. The annual reassessment also ensures the scheme is well targeted and

[4] GreenBe's proposal considers a 1-off fixed cost in year 1, resulting in lower costs from year 2
[5] Based on a $2021 VCR of $21.39 per kWh.

tailored to the networks needs with the most recent information. The Summer Saver 2021/22 costs and benefits, for the 234 sites is shown in Table 6. This demonstrates that UE is eligible for the maximum incentive under the scheme since the net customer benefit exceeds greater than 50% of the expected demand management cost.

Table 6 : Summary of Summer Saver 2021/22 summer costs benefits ($k, 2021)

Option	Description	Costs	Benefits	Net benefit
2	Summer Saver Program	-$338	$841	$503

4 Attachments

4.1 Appendix 1 – Request for Proposals

Ref	File Name	Description
4.1.1	2021_22 Summer DSS - Request for NNS	2021/22 Summer Distribution System Augmentation Program (DSS) – Non Network Proposal Request.

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4.2 Appendix 2 – Cost Declarations

Ref	File Name	Description
4.2.1	2021_22 Summer Saver Cost Declaration - signed	2021/22 Summer Saver Program (SSP22) cost declaration.

4.3 Appendix 3 – Market Assessments

Ref	File Name	Description
4.3.1	SSP22 Market Assessment_2022	2021/22 Summer Saver Program (SSP22) market assessment.

4.4 Appendix 4 – Summer Saver Event Performance Data

Ref	File Name	Description
4.4.1	SSP21 Event Data	2020/21 Summer Saver Program (SSP21) Event Performance Data

4.5 Appendix 5 – Deloitte Audit Report

Ref	File Name	Description
4.5.1	Deloitte Audit Report.	Deloitte Audit Report.

4.6 Appendix 6 – AER DMIS (2017) Annual Compliance Report – Information requirements checklist

Demand Management Incentive Scheme (DMIS) (2017) – information requirements		
DMIS clause	**Description**	**DNSP's summary response**
Compliance reporting:		
2.4(1)	For each regulatory year, the distributor must submit a demand management compliance report to the AER no later than 4 months after the end of that regulatory year to which the reported data pertains.	DMIS Compliance Report submitted.
2.4(2)	The compliance report must be reviewed in accordance with the assurance requirements set out in the annual reporting regulatory information notice applicable to the distributor, at the distributor's expense and by a person permitted to conduct such a review under that regulatory information notice.	Deloitte audit assurance provided as in Appendix 5 (Section 4.5).
2.4(3)	Each compliance report must include two parts—Part A and Part B. Part A includes information on committed projects and Part B contains information on projects that the distributor has identified as eligible projects.	Refer to Section 2 for Part A and section 3 for Part B.
2.4(4)	Each compliance report must include the following information in Part A: (a) The volume of demand management delivered by committed projects in that regulatory year (that is, the kVA per year of demand that a distributor controlled (either directly or indirectly) by means of committed projects in that regulatory year) (b) The distributor's estimate of the benefits realised from the demand management delivered by committed projects in that regulatory year (c) The total financial incentive that the distributor has assessed that it is able to claim in accordance with clauses 2.2, 2.3 and 2.5 of the scheme, for that regulatory year.	Requirements a), b) and c) are addressed for each of the three committed projects in sections 2.1, 2.2, 2.3

2.4(5)	For each eligible project that a distributor identifies as a preferred option in a regulatory year, Part B of the compliance report relating to that regulatory year must include the following information about that eligible project: (d) In present value terms, the expected costs and benefits that the distributor determined, in accordance with clause 2.2 of DMIS, that the eligible project would deliver to electricity consumers (e) A description of the responses that the distributor received to either its RIT–D or its request for demand management solutions under the minimum project evaluation requirements (as relevant) including, for each response: i. a short description of the proposed project ii. the proposed costs and deliverables put forward in the response to the request for demand management solutions; and iii. for any response that proposed a potential credible option, the distributor's estimate of that project's relevant net benefit. (f) Identify whether, if the distributor decides (or has decided) to proceed with the project as a committed project, it is likely that this will occur via a demand management contract, or whether this is likely to occur via a demand management proposal. If the former, the compliance report must also identify the proposed party or parties to the demand management contract. (g) The expected costs of delivering demand management, by means of the eligible project, that the distributor used as an input into its assessment, under clause 2.2, that the project is an efficient non-network option in relation to demand management. (h) the kVA per year of network demand that the distributor: i. would be able to call upon, influence, dispatch or control if the project is implemented (that is, the kVA per year of demand management capacity); and ii. expects to call upon, influence, dispatch or control, based on its probabilistic assessment of future demand, if the project is implemented.	Relevant sections can be referenced in the content of this reports as follows: (d) Section 3.1.3 (e)(i) Section 3.1.1 (e)(ii) Section 3.1.2 (e)(iii) Section 3.1.3 (f) Section 3.1 (g)(h) Section 3.1.2 Also refer to Market Assessment and Cost Benefit Analysis of the eligible projects provided in Appendix 3 (Section 4.3) for all items from (d) to (h).

Demand Management Incentive Scheme (DMIS) (2017) – information requirements		
DMIS clause	**Description**	**DNSP's summary response**
Compliance reporting:		
2.4(6)	Where a distributor decides, in a regulatory year, to defer or not proceed with an eligible project that it has previously decided (either in that regulatory year or in a previous regulatory year) to proceed with as a committed project, the distributor must identify that decision and project in its compliance report for that regulatory year.	Not Applicable.
2.4(7)	Where a distributor decides, in a regulatory year, to 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 project, the distributor must identify that network option and committed project in its compliance report for that regulatory year.	Not Applicable.
2.4(8)	If the distributor's compliance report contains confidential information, the distributor must also provide a non-confidential version of the report in a form suitable for publication. The AER may publish the compliance report (or the non-confidential version of the compliance report, if applicable) on its website.	Not Applicable.
For each identified eligible project:		
2.2(1)	Name and description of the eligible project	Refer to Section 3.1.1.1
2.2(3)	State whether the distributor identified the project as an efficient non-network option through: (a) a RIT-D, or (b) the minimum project evaluation requirements.	This project was identified via minimum project evaluation requirements. Refer to Section 3.1.

Demand Management Incentive Scheme (DMIS) (2017) – information requirements		
DMIS clause	**Description**	**DNSP's summary response**
Compliance reporting:		
2.2(4)	Demonstrate that, in determining by means of the minimum project evaluation requirements whether a project is an efficient non-network option, including when estimating the NPV of the net economic benefit of a project as part of that process, the distributor included: (a) Costs and benefits of a kind that accrue to consumers via the distribution network, and (b) To the extent they exist and may affect the distributor's identification of the preferred option: i. costs and benefits of a kind that accrue to consumers via parts of the relevant market other than the distribution network, and ii. benefits that consist of option value.	Refer to Market Assessment and Cost Benefit Analysis of the eligible projects provided in Sections 3.1.3 and Appendix 3 (Section 4.3).
Minimum project evaluation requirements:		
2.2.1(2)	Where an identified need on its distribution network could be fully or partly addressed by a demand management solution, state whether the distributor issued a request for demand management solutions to the following parties: (a) Persons registered on its demand side engagement register (b) Any other parties the distributor may identify as having or potentially having the capabilities to provide a demand management product, service or solution to either fully or partly form a credible option to address the identified need on the distribution network.	Refer to Request for Proposals provided in Appendix 1 (Section 4.1) and Section 3.1.
2.2.1(3)	State whether the request for demand management solutions in accordance with clause 2.2.1(2) included a request for a quote.	Refer to Request for Proposals provided in Appendix 1 (Section 4.1).

Demand Management Incentive Scheme (DMIS) (2017) – information requirements		
DMIS clause	**Description**	**DNSP's summary response**
Compliance reporting:		
2.2.1(4)	Demonstrate that, as part of the request for demand management solutions, the distributor provided the following information: (a) A description of the identified need that the distributor is seeking to address (b) Technical information about the identified need, including the load at risk, energy at risk, duration and load curves, the annual probability and frequency of relevant events, and the expected value of energy at risk. The expected value of energy at risk must be based, as a minimum, on the average volume of energy at risk, the weighted probability of the energy at risk event occurring, and the relevant value of customer reliability for a given regulatory year (c) The location of the identified need and a description of the affected classes of customers and network area (d) If the distributor has already identified an initial preferred option to meet the identified need on the distribution network, a description of its initial preferred option (e) Other information that is sufficient to enable the parties receiving the request for demand management solutions to provide an informed response in presenting an alternative potential credible option, including, to the extent relevant, the information that a distributor is required under the NER to provide in a non-network options report.	Refer to Request for Proposals provided in Appendix 1 (Section 4.1).

Demand Management Incentive Scheme (DMIS) (2017) – information requirements		
DMIS clause	**Description**	**DNSP's summary response**
Compliance reporting:		
2.2.1(5)	Demonstrate that, in the request for demand management solutions, the distributor required the provision of the following information from responding parties: (a) A description of the proposed demand management product, service or solution that is put forward as a credible option, or as part of a credible option, to address the identified need on the distribution network (b) Where the proposed demand management product, service or solution is put forward as part of a credible option (but not as the whole of a credible option), a description of the other elements of the credible option. (c) A reasonable estimate of: i. The proposed product, service or solution's expected outputs, including the amount of network demand (based on a specified kVA per year) that the party responding to the request for demand management solutions expects to be able to manage (either at its influence, request or control). ii. The expected payments that the distributor would be required to make to the responding party if the distributor were to enter into a contract with the responding party for the responding party to provide that product, service or solution to the distributor. (d) Any other information relevant to determining whether the proposed product, service or solution would be a credible option, or part of a credible option, to address the identified need on the distribution network.	Refer to Request for Proposals provided in Appendix 1 (Section 4.1).
Committed projects:		

Demand Management Incentive Scheme (DMIS) (2017) – information requirements		
DMIS clause	**Description**	**DNSP's summary response**
Compliance reporting:		
2.2.2(1)	For each committed project, provide a copy of the demand management contract or the demand management proposal in accordance with clause 2.2.2.	Refer to Cost Declaration provided in Appendix 2 (Section 4.2)
Determining project incentives:		
2.3(1)	For each committed project, the distributor must calculate the project incentive that the committed project (referred to in clause 2.3 as 'project *i')* can receive.	Refer to Section 2.1, 2.2, 2.3
2.3(2)	The distributor must calculate project *i*'s project incentive in accordance with equation 1, which caps the project incentive to the lower of the following two values: (a) the higher of: i. the expected present value at time *t* of project *i*'s demand management costs, minus the value of subsidies the distributor will receive to provide or procure the demand management component of project *i*, multiplied by the cost multiplier; and ii. zero and (b) the expected present value at time t of the relevant net benefit under project i.	Refer to Section 2.1, 2.2, 2.3

Demand Management Incentive Scheme (DMIS) (2017) – information requirements		
DMIS clause	**Description**	**DNSP's summary response**
Compliance reporting:		
2.3(4)	Demonstrate that the expected value of project *i*'s demand management costs used for the purposes of clause 2.3(2)(a) and equation 1 are consistent with: (a) The payments, or potential payments, for the demand management solution under the demand management contract or in the demand management proposal (as relevant); and (b) The distributor's reasonable expectation of the frequency and duration on which it will call on or utilise the capability to control network demand under the demand management proposal or the demand management contract (as relevant). In order to determine this expectation, the distributor must probabilistically determine the amount of network demand that it expects to request, control or influence.	Refer to Market Assessment and Cost Benefit Analysis of the eligible projects provided in Appendix 3 (Section 4.3).
2.3(5)	Demonstrate that the distributor carried out a cost–benefit analysis to calculate the expected relevant net benefit for project *i* referred to in clause 2.3(2)(b) and equation 1. As part of this cost–benefit analysis, the distributor must estimate project *i*'s net benefit relative to 'the base case', being, in most cases, where the distributor does not implement a credible option to address the identified need. The exception to this 'base case' is that, where the identified need is for reliability corrective action, the distributor will use a credible option that has the second highest net benefit as the base case.	Refer to Market Assessment and Cost Benefit Analysis of the eligible projects provided in Appendix 3 (Section 4.3).