6. DEMAND MANAGEMENT INCENTIVE ALLOWANCE		
6.1	Identify each demand management project or program for which CitiPower seeks approval.	1. Energy Partner Program—integrate new distributed energy resources (**DER**) into our demand response program and better engage customers via a platform that will automatically trigger demand response events 2. Dynamic management of HV generation—allows management of minimum demand to reduce future network augmentation, by dynamically managing HV connected generation. These projects are a combined undertaking between CitiPower and Powercor, given we operate the same systems and the programs will benefit customers across both networks.
6.2	For each demand management project or program identified in the response to paragraph 6.1: (a) explain: (i) how it complies with the Demand Management Innovation Allowance criteria detailed at section 3.1.3 of the demand management incentive scheme; (ii) its nature and scope; (iii) its aims and expected outcomes; (iv) the process by which it was selected, including its business case and consideration of any alternatives; (v) how it was/is to be implemented; (vi) its implementation costs; and (vii) any identifiable benefits that have arisen from it, including any off peak or peak demand reductions; (b) confirm that its associated costs are not: (i) recoverable under any other jurisdictional incentive scheme; (ii) recoverable under any other Commonwealth or State Government scheme; and (iii) included in the forecast capital or operating expenditure approved in the 2016-20 Distribution Determination or recoverable under any other incentive scheme in that determination; and: (c) state the total amount of the Demand Management Innovation	(a)(i), (ii), (iii), (iv), (v), (vii) **1. Energy Partner Program** Our previous version of our energy partner program (EPP) worked by offering eligible customers (i.e. those in locations where our network is constrained) a smart device that controls the temperature settings of their air conditioner during scheduled demand response events. By actively controlling the room temperature for a short period during peak demand times, we have reduced peak load for our targeted feeders and thereby deferred augmentation. Customers receive a payment each time they participate in a control event. Following the successful introduction of the EPP, we have extended the program to distribution substations (DSS). Specifically, we have targeted customers with air conditioners who are directly attached to DSS where peak demand is predicted to exceed their maximum capacity. The implementation of the program uses technology and techniques that differ from those previously applied. This includes a new platform that automatically identifies and schedules demand

	Allowance spent in the Relevant Regulatory Year and how this amount has been calculated.	response events using real-time data and forecast weather conditions. The new platform also allows registration of any type of DER that offers demand management capability, regardless of type, manufacturer or communications protocol (i.e. it seeks to address an existing challenge with demand management programs of disparate communications mediums, program interfaces and protocols). Once successful and operating with large enough customer participation, the extension to our EPP will defer or avoid future DSS augmentation by reducing peak demand to levels within the maximum ratings of the assets. The potential benefits of deferred augmentation are material, as we have around 85,000 distribution transformers installed across our networks. As there are fewer customers on a typical DSS than a typical feeder (the target of our existing program) there are more opportunities to defer augmentation as only a few customers per DSS are potentially required to participate in this program. However, given the greater geographical spread of the program, it also means an automated system is needed plus thus this gives great repeatability and flexibility for future demand management uses. We issued a tender and selected a vendor (mPrest) to deliver this automation. We began this update in the first half of 2020 and completed it in December 2020 in time for the 2020/21 summer period. The aim of our extension to the EPP is to defer (or avoid) future DSS augmentation by reducing peak demand to levels within the maximum ratings of the assets. This program has introduced new software applications that enhance the customer experience and seek to automate the communications and connectivity of customers' appliances. This

includes:

- new technology that automatically identifies peak demand events in the near-future and schedules those demand response events with individual customer devices
- allows for inclusion in the program of any type of DER that offers demand management capability, regardless of type, manufacturer or communications protocol.

This project supports targeted peak demand management, aimed at addressing specific network constraints on our most highly utilised DSS (i.e. customers with air conditioners who are directly attached to DSS whose peak demand is predicted to exceed their maximum capacity).

- Event success is measured by actual kW reduced per event per DSS.
- Event benefits ranged from 6kW to 35kW reduced.

In addition, insight into customer behaviour during events proved a valuable learning experience, as well as customer engagement and marketing requirements.

2. Dynamic management of HV generation

We have a large number of non-scheduled HV generation connections that export electricity directly into the distribution network. As a low marginal cost generation option, renewable embedded generation provides benefits to our customers through offsetting wholesale generation. It also has the potential to keep more customers on supply after a transmission network failure and reduces carbon emissions.

However, the extent of non-scheduled HV generation on our networks, coupled with changing demand and generation profiles of end customers, is increasing the risk of network constraints caused

		by reverse flow at times of minimum demand. That is, lower energy demand (e.g. due to energy efficiency and increased solar use, or even a downstream fault resulting in an outage) is resulting in periods when electricity generated in the distribution network may be forced back upstream, rather than being used locally. More information on the issues of reverse power flow include: 1. Thermal Capacity: At a high level, distributor generator connections are currently made on the basis of worst case system normal conditions defining the capacity available. With a HV DERMS system in place for HV generators, we will be able to better control both existing and new HV generators to better manage reverse power follow dynamically and make best use of our networks capacity. This will help to unlock more generator connections and mean more MW's are available to the market without significant network upgrades. 2. Voltage Control: Distributors are increasingly seeing greater frequency of elevated network voltages as a result of lowering demands and increasing penetrations of both LV and HV generation. With a HV DERMS, voltage improvements can be achieved by reducing HV generation when required to arrest high voltages. Also, where possible, we can issue reactive set point changes to generators to help better control voltage in real time. 3. Under Frequency Load Shedding (UFLS): AEMO and networks currently coordinate to ensure that a portion of demand can automatically be shed to arrest worst case under frequency events. It is becoming increasingly hard to achieve the right amount through normal means in periods of low demand and high generation export. With a HV DERMS we will be a better able to control non-scheduled HV generation, that would otherwise be generating, even in periods of low demand. This will help to address the risk of

		low UFLS resources. While reverse flows driven by existing non-scheduled generators can be addressed by network augmentation, this is a costly option. Therefore, we propose to introduce systems which will offer a dynamic operating model for HV-connected generation. This will ensure supply is balanced with network demand and capability and reduce the need to augment our network. This is achieved through the introduction of a new analytics module that performs load balancing and electricity quality calculations in real-time, offering dynamic management of generation. This uses advanced forecasting of operating envelopes to automatically ramp down generation at times of low demand. Consistent with our existing connections policy, new generators can participate in the initiative through funding the hardware and IT costs as part of the 'incremental cost customer specific' component outlined in the AER's connection charge guideline. The dynamic operating model for these new generators has been shown to enable them to increase their generation output (at suitable times) beyond that which would be allowed under an equivalent static agreement. This model will provide greater flexibility to optimise the use of our network, which ultimately benefits all customers through more locally produced renewable generation. This program will reduce the need for augmentation due to minimum demand by dynamically managing the output of HV generators. This minimum demand management system manages network demand or power flows by interacting with generators on the HV network. This program is a broad-based demand management initiative, as it has the potential to avoid augmentation across our distribution area. This system uses real-time demand, generation and constraints

		calculations to monitor the state of the network and control the injection of independently generated electricity into the network, thus allowing the system to be balanced to maximise network utilisation. We are not aware of such a system being implemented previously in Australia. This system is being implemented via a vendor offering (GE), determined based on limited tender, with additional development based on the bespoke functionality required. The project will be complete 30 June 2021. (a) (vi) The cost of the combined project (1) Energy Partner program and (2) Dynamic management of HV generation in the 2020 year is $3.38M (b) The costs proposed for our extension to the EPP and dynamically managing HV generation are not recoverable under any other jurisdictional or other scheme and are not included in our forecast capital or operating expenditure approved for the 2016–2020 regulatory period. (c) The total amount of DMIA spent in 2020 in CitiPower for the abovementioned projects was $1,013,189.94.
6.3	Provide an overview of developments in relation to projects or programs completed in previous years of the regulatory control period, and of any results to date. Note: Information provided in response to paragraph 6 of Schedule 1 to this Notice will constitute the provision of an annual report for the purposes of paragraph 3.1.4.1 of the Demand Management Incentive Scheme applying to CitiPower (as set out in the 2016-20 Distribution Determination)	An early version of the Energy Partner demand response program was run last year. This concept has been enhanced as per the description in 6.2.