AER Final RIN – CITIPOWER Schedule 1 Response

1. REGULATORY ACCOUNTING STATEMENTS & NON-FINANCIAL INFORMATION		
1.1(a)	Provide the Regulatory Accounting Statements, being the information required in the worksheets in the Microsoft Excel workbook attached at Appendix B; as amended by the AER on 6 August 2014;	Please refer to accompanying Appendix B Templates 1-29
1.1(b)	Provide the non-financial information required in the worksheets in the Microsoft Excel workbook attached at Appendix C, as amended by the AER on 6 August 2014;	Please refer to accompanying Appendix C Templates 1a-4c
1.1(c)	Provide a Microsoft Excel workbook that reconciles and explains adjustments between the Statutory Accounts and the Regulatory Accounting Statements. CitiPower must separately list each adjustment to the Statutory Accounts made to derive the Regulatory Accounting Statements, and for each adjustment made: (i) specify the amount of the adjustment (ii) describe the nature and basis of each adjustment	Please refer to "Attachment 1 – 1.1(c) Stat to Reg CitiPower 2014"
1.1(d)	Provide a Basis of Preparation demonstrating how CitiPower has complied with the Notice, in accordance with this Notice and the Principles and Requirements at Appendix A	Please refer to accompanying Basis of Preparation documents
1.1(e)	Provide the Regulatory Accounting Principles and Policies and the Capitalisation Policy for the Relevant Regulatory Year.	Please refer to "Attachment 2 – 1.1(e) Regulatory Accounting Principles and Policies CP"
1.1(f)	Provide a statement of the policy for determining the allocation of overheads in accordance with the approved *Cost Allocation Method* for the Relevant Regulatory Year.	Overhead rates are applied by the SAP system to directly attributable costs for corporate, network, system control and fleet and property labour and service costs which are, in accordance with CitiPower's statutory accounting policies, attributable to the function of preparing an asset ready for use or of maintaining an asset. The network overhead pool is sourced from costs which are shared and allocated between CitiPower and Powercor as described in section 11.3 of

<table>
<tr><td></td><td></td><td>CitiPower’s Cost Allocation Methodology.</td></tr>
<tr><td>1.2</td><td>Identify all changes between the Regulatory Accounting Principles and Policies provided in the response to paragraphs 1.1(e). For each change identified:
(a) explain the nature of and the reasons for the change; and
(b) quantify the effect of the change on the Regulatory Accounting Statements for the Relevant Regulatory Year.</td><td>There are no changes between the Regulatory Accounting Principles and Policies provided in response to paragraphs 1.1(e)</td></tr>
<tr><td>1.3</td><td>Identify all changes between the statements of the policy for determining the allocation of overheads in accordance with the approved Cost Allocation Method provided in the response to paragraph 1.1(f). For each change identified:
(a) explain the nature of and the reasons for the change; and
(b) quantify the effect of the change on the Regulatory Accounting Statements for the Relevant Regulatory Year.</td><td>There are no changes between the statement of the policy for determining the allocation of overheads in accordance with the Cost Allocation Method provided in the response to paragraphs 1.1(f).</td></tr>
<tr><td>1.4</td><td>Identify each material difference (where the difference is equal to or greater than ±10%) between the amount reported in the Regulatory Accounting Statements and the amount provided for in the 2011–15 Distribution Determination, for the following:
(a) total actual revenue and total forecast revenue;
(b) total actual operating expenditure and total forecast operating expenditure;
(c) total actual maintenance expenditure and total forecast maintenance expenditure;
(d) total actual capital expenditure and total forecast capital expenditure; and
(e) total actual energy sales and total forecast energy sales.</td><td>(a) The difference between the total actual revenue and total forecast revenue is not material.

(b) The difference between the total actual operating expenditure and total forecast operating expenditure is not material.

(c) The difference between the total actual maintenance expenditure and total forecast maintenance expenditure is as follows:

<table>
<tr><th>Category</th><th>Variance</th></tr>
<tr><td>Routine</td><td>(39.6%) / ($2.8M)</td></tr>
<tr><td>Condition based</td><td>38.2% / $4.2M</td></tr>
<tr><td>Emergency</td><td>36.6% / $1.4M</td></tr>
<tr><td>SCADA/Network Control</td><td>426.1% / $0.1M</td></tr>
<tr><td>Other - Standard Control Services</td><td>32.4% / $0.7M</td></tr>
<tr><td>TOTAL</td><td>15.1% / $3.6M</td></tr>
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<table>
<tr>
<td></td>
<td></td>
<td>(d) The difference between the total actual capital expenditure and total forecast capital expenditure is as follows:
(e)
<table>
<tr><th>Category</th><th>Variance</th></tr>
<tr><td>Reinforcements</td><td>(14.5%) / ($7.3M)</td></tr>
<tr><td>New Customer Connections</td><td>1.5% / $0.9M</td></tr>
<tr><td>Reliability & Quality Maintained</td><td>(38.8%) / ($13.9M)</td></tr>
<tr><td>Environmental, Safety & Legal</td><td>44.2% / $3.2M</td></tr>
<tr><td>SCADA Network Control</td><td>(21.6%) / ($0.6M)</td></tr>
<tr><td>Non network general assets - IT</td><td>(43.4%) / ($5.5M)</td></tr>
<tr><td>Non network general assets - Other</td><td>34.4.1% / $1.2M</td></tr>
<tr><td>Customer contributions</td><td>66.3% / $7.7M</td></tr>
<tr><td align="right">TOTAL</td><td>(18.6%) / ($29.8M)</td></tr>
</table>

(f) The difference between total actual demand and total forecast demand is not material.</td>
</tr>
<tr>
<td>1.5</td>
<td>Explain the reasons that caused each material difference identified in the response to paragraph 1.4.</td>
<td><u>Maintenance Expenditure</u>
Routine: The absolute expenditure variance is not material.

Condition based: Actual volumes of work have increased in line with the general ageing of the network.

Emergency: Variance is not material in the context of uncontrollable nature of work volume.

SCADA/Network Control: Actual costs more reflective of the work volume than allowed in the 2011-15 EDPR.

Other – Standard Control Services: The absolute expenditure variance is not material.

<u>Capital Expenditure</u>
Reinforcements: Expenditure is less than forecast at the 2011-15 EDPR Final Determination as a result of: 1. While the initial stages of the CBD Security</td>
</tr>
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		Project have been completed, the final stages of the project have been delayed as a result of more detailed analysis of options relating to the condition of the substation W building. The conclusion of the options analysis is to proceed with the plan to demolish and replace the W building, which has now commenced. 2. The delay in the development of the Brunswick Terminal Station by AusNet Services has changed the timing of several elements of the Metro Capacity Upgrade Project, and other projects that would have increased the 66kV supply requirements from the now constrained West Melbourne Terminal Station. These delayed projects have been partially offset by reinforcement expenditure to provide replacement capacity to allow for the decommissioning of the Prahran zone substation. *New Customer Connections:* Economic conditions are still improving following the impacts of the GFC, resulting in less connection expenditure in 2014 than forecast at the 2011-15 EDPR. *Reliability and Quality Maintained:* Efficiencies realised by the strategy of decommissioning ageing zone substations and avoiding replacement expenditure, but with some offsetting reinforcement expenditure. *Environmental, Safety and Legal:* Work volumes related to overhead lines were greater than forecast at the 2011-15 EDPR. *SCADA Network Control:* The absolute expenditure variance is not material. *Non network general assets – IT:* Over the regulatory period standard control systems have been maintained and enhanced due to the focus on the implementation of smart meter related systems (not included in the analysis below). Beginning in 2014, CitiPower has re-commenced its investment in these standard control systems. *Non network general assets – Other:* Purchase of new fleet including a crane borer and light fleet to support operational requirements; and upgrade of the fleet to address changes in safety and compliance as required by Australian Standards (AS) or Australian Design Rules (ADR). *Customer contributions:* Undertaken more customer funded projects than forecast

<table>
<tr>
<td>1.6</td>
<td>Identify each material difference (where the difference is equal to or greater than ±10%) between the target performance measure specified in the service target performance incentive scheme and actual performance reported in the response to paragraph 1.1(b).</td>
<td>CitiPower is rewarded or penalised under the AER's Service Target Performance Incentive Scheme (STPIS) which covers our reliability performance and telephone response. The applicable parameters include unplanned SAIDI, unplanned SAIFI and MAIFI reliability of supply parameters and the telephone answering customer service parameter, defined as follows:

Unplanned SAIDI: The average number of minutes in a year customers are without supply due to unplanned events;
Unplanned SAIFI: The average number of times in a year customers experience sustained interruptions due to unplanned events;
MAIFI: The average number of times in a year customers experience momentary interruptions; and
Telephone answering: The percentage of calls answered within 30 seconds.

Actual STPIS outcomes versus the AER targets are set out in the table below:
<table>
<tr><th colspan="5">CitiPower - 2014</th></tr>
<tr><th colspan="2">Measure</th><th>AER Target</th><th>Actual</th><th>Variance (%)</th></tr>
<tr><td rowspan="3">CBD</td><td>USAIDI</td><td>11.271</td><td>12.168</td><td>(8)</td></tr>
<tr><td>USAIFI</td><td>0.186</td><td>0.148</td><td>20</td></tr>
<tr><td>MAIFI</td><td>0.026</td><td>0.000</td><td>100</td></tr>
<tr><td rowspan="3">Urban</td><td>USAIDI</td><td>22.36</td><td>42.498</td><td>(90)</td></tr>
<tr><td>USAIFI</td><td>0.450</td><td>0.492</td><td>(9)</td></tr>
<tr><td>MAIFI</td><td>0.175</td><td>0.247</td><td>(41)</td></tr>
<tr><td colspan="2">Telephone Answering (%)</td><td>71.52</td><td>78.37</td><td>9</td></tr>
</table>
</td>
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<tr>
<td>1.7</td>
<td>Explain the reasons that caused each material difference identified in the response to paragraph 1.6.</td>
<td><u>Reliability</u>
CitiPower under performed against the AER targets for CBD USAIDI (i.e. unplanned SAIDI) and Urban USAIDI, USAIFI (i.e. unplanned SAIFI) and MAIFI. The main causes for the negative performance in CitiPower's CBD network was due to interruptions caused by equipment failure, outages caused by a third party such as vehicle impacts and animals shorting out power lines. The main causes for the negative performance in CitiPower's Urban network was due to interruptions caused by equipment failure, vegetation contact with power lines, animals shorting out power lines and bad weather conditions.</td>
</tr>
</table>

		Telephone Answering Telephone Grade of Service (**GOS**) performance in 2014 was favourable to AER targets for CitiPower.
1.8	Where it is not possible to provide the information in Schedule 1 as required by the Notice, provide: (a) An estimate, using best endeavours to generate the most appropriate estimate; and (b) The basis for this estimate, explaining why it is the most appropriate estimate; or (c) If it is not possible to provide an estimate, explain why the information as required by this Notice has not been provided, and why an estimate is not able to be derived.	Please refer to accompanying Basis of Preparation documents
2. COMPLIANCE		
2.1	Explain the procedures and processes used by CitiPower to ensure that the distribution services have been classified as determined in the 2011-15 Distribution Determination.	Please refer to Cost Allocation Methodology and Basis of Preparation documents.
2.2	Explain the procedures and processes used by CitiPower to ensure that the negotiated service criteria, as set out in the 2011-15 Distribution Determination, have been applied.	Negotiated services are customer requests to alter or relocate public lighting assets and customer requests for new public lighting. Customer requests for public lighting services are treated in a similar way to a customer request for supply or to relocate assets. The request is negotiated based on CitiPower's network policies and all offers to customers are based on standard customer agreements in line with the negotiating framework approved by the AER. The timeframes to provide offers are monitored and reported annually to CitiPower's Compliance Committee and Regulation team.
2.3	Describe the process CitiPower has in place to identify negative change events under clause 6.6.1(f) of the NER and the materiality threshold applied to these events.	CitiPower continuously scans for a regulatory change event, a service standard event, a tax change event and a retailer insolvency event. If a negative change event occurs, CitiPower estimates the resulting incremental standard control service cost saving. If the estimated incremental cost saving is greater than one per cent of annual standard control revenue, CitiPower will notify the AER within 90 business days of becoming aware of the occurrence of a negative change event.

3. COST ALLOCATION TO THE REGULATED DISTRIBUTION BUSINESS		
3.1	Identify each Item in the Regulatory Accounting Statements that is: (a) not allocated on a directly attributable basis but is allocated on a causation basis to CitiPower; or (b) not allocated on a directly attributable basis and cannot be allocated on a causation basis to CitiPower.	Please refer to the CAM.
3.2	For each Item identified in the response to paragraphs 3.1(a): (a) state the amount of the item that has been allocated; (b) explain the method of allocation and reasons for choosing that method; and (c) state the numeric amount of the allocator(s) used.	Please refer to the CAM.
3.3	For each Item identified in the response to paragraph 3.1(b): (a) state its amount; (b) state whether it was Material; (c) explain the method of allocation and reasons for choosing that method; and (d) explain the reason(s) why it cannot be allocated on a causation basis.	Please refer to the CAM.
4. COST ALLOCATION TO SERVICE SEGMENTS Note: service segment refers to standard control services, Advanced Metering Infrastructure (AMI), alternative control services, negotiated services and unregulated services.		
4.1	Identify each item in the Regulatory Accounting Statements that is: (a) Not allocated on a directly attributable basis but is allocated on a causation basis from CitiPower to a service segment; and (b) Not allocated on a directly attributable basis and cannot be allocated on a causation basis from CitiPower to a service segment.	Please refer to Appendix B – additional tab “Income Work Paper”
4.2	For each item identified in the response to paragraph 4.1(a): (a) State the amount of the item that has been allocated; (b) Explain the method of allocation and reasons for	Please refer to Appendix B – additional tab “Income Work Paper”

	choosing that method; and (c) State the numeric amount of allocator(s) used.	
4.3	For each item identified in the response to paragraph 4.1(b): (a) State its amount; (b) State whether it was Material (c) Explain the method of allocation and reasons for choosing that method (d) Explain the reason(s) why it cannot be allocated on a causation basis.	Please refer to Appendix B – additional tab “Income Work Paper”
	5. RELATED PARTY TRANSACTIONS	
5.1	Identify each Related Party to which a transaction has been conducted.	Please refer to Appendix B – Template 20 “Related party transactions”
5.2	Identify each transaction relating to the provision of standard control services, alternative control services, AMI or negotiated distribution services between CitiPower and a Related Party, where the transaction amount is greater than five per cent of the relevant total expenditure or revenue category. Relevant categories are standard control revenues, alternative control revenues, AMI revenues, negotiated distribution services revenues, standard control capex, alternative control capex, AMI capex, standard control operations expenditure, standard control maintenance expenditure, alternative control operations expenditure, alternative control maintenance expenditure AMI operations expenditure, AMI maintenance expenditure, and negotiated distribution services expenditure.	Please refer to Appendix B – Template 20 “Related party transactions”
5.3	For each transaction identified in the response to paragraph 5.2: (a) state the name of the Related Party; (b) identify any other parties involved; (c) explain the nature and purpose of the transaction, including the good(s) or service(s) provided by the Related Party; (d) state the actual costs incurred by the Related Party in providing good(s) or services(s), not including any profit margin or management fee incurred by CitiPower;	Please refer to Appendix B – Template 20 “Related party transactions”

	(e) explain how the actual costs of the good(s) or service(s) incurred was determined; (f) explain how the actual costs of the good(s) or service(s) incurred is reflected in the Regulatory Accounting Statements; (g) identify the Asset Category, Maintenance Cost category or Operating Cost category to which the actual cost(s) is allocated to; and (h) explain the basis upon which the actual costs of the good(s) or service(s) were allocated, as identified in the response to paragraph 5.3(f), and state the quantum of any allocator applied.	
	6. CAPITALISATION POLICY	
6.1	Identify all changes between the Capitalisation Policies provided in the response to paragraph 1.1(e).	There are no changes to the Capitalisation Policy Statements provided in response to paragraph 1.1(e).
6.2	For each change identified in the response to paragraph 6.1: (a) state, if any, the financial impact of the change; (b) state the reasons for the change; (c) explain the effect of the change, if any, on the actual operating expenditure, actual maintenance expenditure, and actual capital expenditure incurred, in comparison to the forecast operating expenditure, forecast maintenance expenditure and forecast capital expenditure determined in the 2011–15 Distribution Determination during the Relevant Regulatory Year; and (d) explain the effect of the change, if any, on the actual operating and maintenance expenditure and actual capital expenditure incurred, in comparison to the previous Relevant Regulatory Year.	There are no changes to the Capitalisation Policy Statements provided in response to paragraph 1.1(e).
	7. DEMAND MANAGEMENT INCENTIVE ALLOWANCE	
7.1	Identify each demand management project or program for which CitiPower seeks approval.	**A. Network Support WMTS 2013/14 Summer** **B. Jacobs Fault Level Mitigation Study Scope #1** **C. Jacobs Fault Level Mitigation Study Scope #2** **D. AEMO Data provision (Supports Jacobs Fault Level Mitigation Study)** **E. Storage Investment Framework Design and Analysis**

7.2	For each demand management project or program identified in the response to paragraph 7.1: (a) explain: (i) how it complies with the Demand Management Incentive Allowance criteria set out at section 3.1.3 of the *demand management incentive scheme*; (ii) its nature and scope; (iii) its aims and expectations; (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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination; and (c) explain any assumptions and/or estimates used in the calculation of forgone revenue, demonstrating the reasonableness of those assumptions and/or estimates in calculating forgone revenue, including the reasons for CitiPower's decision to adjust or not to adjust for other factors and the basis for any such adjustments.	**A. Network Support WMTS 2013/14 Summer** (a) (i) The project was a trial of an inner urban location demand side initiative, which had the effect of deferring capital expenditure. (ii) This was a network support project which involved an existing embedded generator operating 2 x 6MW gas fired generators. A network support agreement was established to enable these generators to provide coincidental capacity support to the Bouverie St zone substation which supplies Carlton, parts of North Melbourne and the northern fringe of the Melbourne CBD. (iii) The aims and expectations of the project were to test the performance, contractual arrangements and support outcomes including operational capability. The project was also initiated to enable deferment of the requirement of an augmentation to transfer load to the BSBQ 66kV supplied system until BTS 66kV supply is available to relieve the constrained WMTS 66kV system. (iv) The process for selection involved consideration of options over a short period of time including demand management, network augmentation and network support. The demand management option was considered against customer requirements in the area and previous experience, and considered that DM at this point would be inflexible and difficult to coordinate. Augmentation in the short term of the 22kV system would be very expensive and transfer to the 66kV not permissible without overloading the 66kV system. This favoured the network support option. (v) The embedded generation owner was engaged by CitiPower via a network support agreement. The agreement was in place for the period of 1st January to 31st March 2014 via 2 x 6MW gas fired generators, already installed and connected to the network from the existing premises. (vi) The implementation costs were $15,000 for contract establishment, followed by $30,000 per month for generation support. Total cost was $105,000 for the period of 1st January to 31st March 2014. (vii) Benefits included learnings from the experience of engaging with an embedded generator for network support including the performance of the local generator from an operational perspective, the time taken to establish an agreement contract as well as the terms and conditions and expected approximate cost for future support; Another benefit is the deferral of the augmentation until BTS is available. (b) its associated costs were 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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been made. **B. Jacobs Fault Level Mitigation Study Scope #1** (a)(i) The project was to explore opportunities within the CitiPower network to examine wider network and transmission solutions to resolve inherent fault level issues within the CBD and permit additional embedded generation connections as potential non-network solutions to existing and forecast capacity constraints. (ii) The project assessed the indicative fault level headroom across the CitiPower distribution network within the Melbourne CBD originating from four terminal stations (FBTS, BTS, RTS, WMTS). An indicative level of generation size that could be permitted at each zone substation was also determined. Network solutions were then explored to increase fault level headroom if a network bus was identified as approaching its fault level limit, to facilitate future additional embedded generation connections. (iii) The aims and expectations of the project were to confirm and receive an independent review of zone substations approaching fault level limit, gain an understanding of existing fault level headroom, determine an indicative level of generation size that could be permitted at each zone substation, and identify any network solutions to increase fault level headroom to facilitate future additional embedded generation connections. (iv) the process for selection involved comparing the capabilities of consultants to do this study. As Jacobs had already completed a similar study in 2011 they were selected. (v) The project was conducted by Jacobs Consulting on behalf of CitiPower. The findings were provided to CitiPower in a project report and presentation. The project occurred throughout 2014. (vi) The project costs were $95,804. (vii) The benefits were to gain a better understanding of the existing transmission imposed network constraints and possible solutions to accommodate future additional embedded generators onto the network to potentially offer non-network solutions to existing and forecast fault level constraints. Details as stated in the aims and expectations above.

		(b) its associated costs were 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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been made. **C. Jacobs Fault Level Mitigation Study Scope #2** (a)(i) The project was to develop a strategy to mitigate fault levels at constrained network locations. The aim was to develop a generic strategy that could be applied to resolve any future fault level constraints on the network to facilitate future additional embedded generation connections as potential non-network solutions to existing and forecast capacity constraints. (ii) The project assessed fault levels at zone substations over the five year outlook period (2015 – 2019), considering load forecasts and network augmentations. Fault level mitigation strategies were then considered for zone substations approaching fault level limit. The preferred options were identified based on technical and economic viability. A high level review of fault mitigation strategies adopted by other distribution businesses was also performed. (iii) The aims and expectations of the project were to identify future fault level issues and establish a fault level mitigation strategy including preferred options to address fault level constraints to accommodate future additional embedded generation connections. (iv) the process for selection involved comparing the capabilities of consultants to do this study. As Jacobs had already completed a similar study in 2011 they were selected. (v) The project was conducted by Jacobs Consulting on behalf of CitiPower. The findings were provided to CitiPower in a project report and presentation. The project occurred throughout 2014. (vi) The project costs were $138,900. (vii) The benefits were to gain a better understanding of future network availability and establish a strategy which recommends preferred distribution

		network solutions to accommodate future additional embedded generators onto the network to potentially offer non-network solutions to existing and forecast capacity constraints. Details as stated in the aims and expectations above. (b) its associated costs were 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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been made. **D. AEMO Data provision (Supports Jacobs Fault Level Mitigation Study)** (a)(i) The transmission system data provision to Jacobs Consulting enabled commencement of scope #1 of their CitiPower Fault Level Mitigation Study. Refer DMIS RIN entry for Jacobs scope #1. (ii) To provide Operations and Planning Data Management System (OPDMS) 1 hour snapshot data to Jacobs Consulting to enable commencement of scope #1 of their CitiPower Fault Level Mitigation Study. Refer DMIS RIN entry for Jacobs scope #1. The OPDMS data contains solved load flow cases which represent the configuration of the transmission system at a point in time, per hour, for the period of 01 July to 30 June 2011. (iii) The aim of the data provision was to enable Jacobs Consulting to commence scope #1 of their CitiPower Fault Level Mitigation Study. Refer DMIS RIN entry for Jacobs scope #1. (iv) AEMO is the only source of the required data. There was no process by which AEMO was selected. (v) Data provision was provided by USB memory card. (vi) The data provision cost $1,900. (vii) The data enabled an accurate study of existing fault level issues based on real time network configuration information. Refer DMIS RIN entry for Jacobs scope #1. (b) its associated costs were 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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been made. **E. Storage Investment Framework Design and Analysis** (a)(i) Storage Investment Framework Design and Analysis involved three main development areas for application of energy storage for demand management: • End-user off gridding • Cold thermal energy storage • Grid Level energy storage on the grid DMIS Criteria numbered and associated responses 1. Non-network in nature through investigating alternative supply options for suitable customers, load shifting and peak curtailment providing alternative means of meeting demand. 2. Program addresses peak demand management and broad-based demand management through identifying best cases for the application of thermal storage, off gridding and network based storage. 3. Builds knowledge and capability to efficiently deploy demand management solutions relevant to the network. 4. Program is non-tariff based. 5. There is no other scheme under which funding can be obtained nor is there provision in the distribution determination for this activity. 6. Expenditure was treated as opex. (ii) New ideas, challenge of existing technical solutions and business models through global benchmark and study of best in (storage) class countries. For each storage development area above, generate: • Suitable technologies (pure storage or hybrid with generation) • Design, sizing and initial cost estimate • Improvement through complementary solutions (energy efficiency, demand side management etc.) • Role of involved stakeholders, regulatory status, revenue sources. • Construction of a full business case for a standard example of each case.

		Integration of cases and associated value ranges, solutions and decision rules into a decision-helper tool for the network to make decisions in the future for similar cases. (iii) Identify the best technical and economical solutions for energy storage demand management cases, assess each solution's profitability and potential market, provide the network with appropriate tools to assess and forecast energy storage projects. (iv) Current forecasts are for storage technologies to significantly reduce in cost in the next 5-10 years, with significantly increased storage penetration into the grid to help manage peak load and intermittent/renewable generation. The SIFDA project was picked due to its future network importance and ability to prepare the network for more energy storage demand management opportunities. (v) Project implemented –August 2014 to January 2015, and involved engagement of ENEA Consulting with specific expertise in energy storage. Extensive data collected from global benchmark and utilised to determine most relevant and economical storage cases. Regular meeting and data collection from internal groups for development of first project opportunities for end-user off gridding, cold thermal energy storage and grid level energy storage. (vi) Hourly rates from employees and service providers. Cost derived from invoices from energy storage service provider and proposal cost estimate (vii) The project equips the business with knowledge, network case studies and tools to deploy relevant and economical energy storage for peak shifting and demand management. Trial projects targeted from the SIFDA analysis will target reductions in traditional network demand. (b) its associated costs were 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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been

		made.
7.3	State the total amount of the Demand Management Incentive Allowance spent in the Relevant Regulatory Year and explain how it was calculated Note: Information provided in response to paragraph 7 of schedule 1 to this Notice will constitute the provision of an annual report for the purpose of paragraph 3.1.4.1 of the AER, Demand Management Incentive Scheme- CitiPower, Powercor, Jemena, SP AusNet and United Energy 2011-15: Part A- Demand Management Innovation Allowance, April 2009.	A. Network Support WMTS 2013/14 Summer - $105,000 B. Jacobs Fault Level Mitigation Study Scope #1 - $95,804 C. Jacobs Fault Level Mitigation Study Scope #2 - $138,900 D. AEMO Data provision (Supports Jacobs Fault Level Mitigation Study) - $1,900 Costs are predominantly external contract costs. E. Storage Investment Framework Design and Analysis - $62,326 Costs are derived from invoices from external service provider and proposal cost estimates.
8. ADVANCED METERING INFRASTRUCTURE		
8.1	Describe each efficiency improvement made to CitiPower's operations directly or indirectly arising from or associated with the roll out of the Advanced Metering Infrastructure. For example: operational cost savings for CitiPower arising from remote meter reading and connection and disconnection of customers' supplies; more efficient outage detection and rectification; improved accuracy of customer billing.	1. Avoided non AMI meter supply cost for new connections and meter replacements - $763,635 2. Avoided non AMI meter supply & installation cost for fault meter replacements - $148,642 3. Avoided non AMI meter replacements resulting from solar installations - $585,830 4. Avoided cost of routine meter testing costs - $251,614 5. Avoided cost of routine non AMI meter reading - $905,975 6. Avoided cost of non AMI special reads - $531,473
8.2	For each efficiency improvement identified in the response to paragraph 8.1: (a) explain how it arises from or is associated with the roll out of the Advanced Metering Infrastructure; and (b) if quantifiable, state its amount.	1. Meter Supply for new connections and meter replacements – accumulation meter supply - the meter supply cost for accumulation meters that would have been supplied if AMI meters hadn't been used. 2. Meter supply and installation cost for fault meter replacements – the meter supply and installation cost for meters that would have been replaced under fault conditions if new AMI meters hadn't been installed via the rollout. 3. Solar Meter replacements / Meter Reconfiguration - the number of manually read interval meters that would have been installed (replacing accumulation meters) for solar installations. Under the AMI Program, existing AMI meters have been reconfigured for solar installations, avoiding the cost of the meter replacement.

		4. Meter testing costs - the costs of testing that would have been carried out if AMI meters hadn't been used. 5. Meter reading - the avoided cost to manually read type 5 and type 6 meters as a result of meters now being read remotely. 6. Special reading - the avoided cost to manually read type 5 and type 6 meters for re-energisation and de-energisation of type 5 and type 6 meters as a result of meters now being read remotely for re-energisation and de-energisation.
9. SAFETY AND BUSHFIRE RELATED EXPENDITURE		
9.1	For each safety and bushfire related expenditure, specify and define the relevant asset category to which it relates.	Please refer to Appendix B Template 22 "Safety and Bushfire Related Expenditure"
9.2	Identify each material difference (where the difference is equal to or greater than ±10%), in relation to the asset categories specified in the response to paragraph 9.1, between: (a) actual and forecast volumes; (b) actual and forecast expenditure; and (c) actual and forecast unit costs.	Please refer to Appendix B Template 22 "Safety and Bushfire Related Expenditure"
9.3	Provide reasons for each material difference (where the difference is equal to or greater than ±10%) identified in the response to paragraph 9.2.	Please refer to Appendix B Template 22 "Safety and Bushfire Related Expenditure"
9.4	Provide reasons for any difference between the actual volumes submitted as part of the Electrical Safety Management Scheme to Energy Safe Victoria and that in the Regulatory Accounting Statements.	CitiPower does not have agreed safety programs and targets. CitiPower did not set annual targets. The CitiPower figures indicated in the Safety Performance report on Victorian Electricity Networks are figures that were supplied to AER for revenue determination purposes only, based on five year average. It is not accurate to report these as agreed targets. CitiPower undertake required actions from asset inspection programs and do not have target replacement numbers. It is not appropriate to report specific annual quantities replaced against these numbers, per category, as a measure of our safety performance. Whilst no safety targets were submitted, in accordance with findings identified via CitiPower's asset inspection process, all rectifications were 100% compliant with the maintenance policy rectification timeframes.
10. SPONSORSHIP AND MARKETING		

10.1	Provide the following information for all advertising/marketing expenditure allocated to the distribution business: (a) For expenditure greater than five per cent of the advertising/marketing expenditure allocated to the distribution business: i. Beneficiary ii. Amount iii. Purpose iv. Proportion of the total advertising/marketing expenditure allocated to the distribution business related to: 1) Safety or safety awareness 2) Managing consumer demand 3) Promoting distribution business brand 4) Other v. Description of the activities undertaken by the beneficiary, supported by the expenditure. (b) For all advertising/marketing expenditure allocated to the distribution business not reported under 10.1(a), provide: i. List of beneficiaries ii. Total amount iii. Proportion of the expenditure related to: 1) Safety or safety awareness 2) Managing consumer demand 3) Promoting distribution business brand 4) Other	**A. Landcare** **B. City of Port Phillip** **C. Doxa Youth Foundation** **D. Melbourne Open House Inc.** **A. (a)(i) Landcare** (ii) $36,875 (iii) Raise environmental awareness (iv) Promoting CitiPower brand (v) Tree planting and community environmental projects **B. (a)(i) City of Port Phillip** (ii) $42,500 (iii) Business Award sponsorship (iv) Promoting CitiPower brand (v) Promotion of local businesses by the City of Port Phillip C. **(a)(i) Doxa Youth Foundation** (ii) $10,000 (iii) Support community awareness (iv) Promoting CitiPower brand (v) Doxa improves the life outcomes of disadvantaged young people **D. (a)(i) Melbourne Open House Inc.** (ii) $10,000 (iii) Promote safety awareness and brand (iv) Promoting CitiPower brand (v) City of Melbourne showcases historic buildings within their area (b)(i) Green Collect, Around the Bay in a Day, Corporate Games, OHM Boards for J Substation (ii) $5,699 (iii) Promoting distribution business brand – 56% Other – 44%
10.2	For each expenditure item identified in response to paragraph 10.1(a), identify the expenditure item in the statutory accounts from which it is derived.	All of the items listed in 10.1 form part of the Sponsorship account which is included in “Expenses from ordinary activities” in the Statement of Profit or Loss in the Statutory accounts. This item is expanded in Note 2(b) of the

		accounts. All items are included under the category “Other expenses”.
11. CHARTS		
11.1	Provide a chart that sets out: (a) the group corporate structure which CitiPower is a part; and (b) the organisational structure of CitiPower.	(a) Please refer to “Attachment 3 – 11.1(a) CP Group Corporate Structure Inc Spark” (b) Please refer to “Attachment 4 – 11.1(b) Executive Management Team Dec 2014”
12. AUDIT REPORTS		
12.1	Provide an Audit Report/s in the form of: (a) a Special Purpose Financial Report in accordance with the requirements set out at Appendix E; and (b) an Audit Report (for non financial information) in accordance with the requirements set out at Appendix E.	(a) Please refer to “Attachment 5 - 12.1(a) CitiPower Annual RIN 2014 Deloitte Audit Report (Financial)” (b) Please refer to “Attachment 6 - 12.1(b) CitiPower Annual RIN 2014 Deloitte Assurance Report (Non-financial)”
12.2	Provide all reports from the Auditor to CitiPower’s management regarding the audit review and/or auditors’ opinions or assessment.	Please refer to “Attachment 7 – 12.2 Deloitte-Regulatory Report-2014”
13. CONFIDENTIAL INFORMATION		
13.1	If CitiPower makes a claim for confidentiality over any information provided in accordance with this Notice, CitiPower must: (a) Comply with the requirements of AER’s Confidentiality Guideline, as if it extended and applied to responses to this Notice; (b) Provide, in addition to a confidential version of any information, a version of the information that may be published by the AER.	(a) CitiPower has claimed for confidentiality in relation to Appendix B Template 20 Related Party Transactions. Please refer to “Attachment 8 – 13.1 AER Confidentiality Template - 2014 CP&PAL” (b) Public and confidential versions of the financial templates have been provided to the AER.
13.2	Confirm in writing that CitiPower consents to the AER publically disclosing (including on the AER website) all information provided in accordance with this Notice, except the confidential version of information the subject of a confidentiality claim under paragraph 13.1.	CitiPower consents to the AER publically disclosing (including on the AER website) all information provided in accordance with this Notice, except the confidential version of information the subject of a confidentiality claim under paragraph 13.1.