CITIPOWER PTY

REGULATORY PROPOSAL: 2011 TO 2015

30 NOVEMBER 2009

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CitiPower's Regulatory Proposal 2011-15 - Abbreviations

ID	Abbreviation	Description
1	ACR	Auto Circuit Recloser
2	Act	Victorian Electricity Safety Act 1998
3	ACT	Australian Capital Territory
4	AEMA	Australian Energy Market Agreement
5	AEMC	Australian Energy Markets Commission
6	AEMO	Australian Energy Market Operator
7	AER	Australian Energy Regulator's
8	AMI	Advanced Metering Infrastructure
9	Aon	Aon Risk Services Australia Ltd
10	ARPANSA	Australian Radiation Protection and Nuclear Safety Agency
11	ARR	Annual Revenue Requirement
12	AS	Australian Standards
13	ASIC	Australia Standard Industrial Classification
14	ASX	Australian Stock Exchange
15	ATO	Australian Tax Office
16	B2B	Business-to-Business
17	bppa	Basis points per annum
18	CAM	Cost Allocation Methodology
19	CBD	Central Business District
20	CBRM	Condition Based Risk Management
21	CEG	Competition Economists Group
22	CGS	Commonwealth Government Securities
23	CHED Services	CHED Services Pty Ltd (ACN 112 304 622)
24	CHEDHA	CHED Holdings Australia
25	CIC	Capital Investment Committee
26	CIS	Customer Information System
27	CitiPower	CitiPower Pty (ACN 76 064 651 056)
28	CKI	Cheung Kong Infrastructure Ltd
29	Code	Victorian Electricity Distribution Code
30	CoF	Consequence of Failure
31	CPI	Consumer Price Index
32	CPRS	Carbon Pollution Reduction Scheme
33	CSIRO	Commonwealth Scientific and Research Organisation

ID	Abbreviation	Description
34	Deloitte	Deloitte Touche Tohmatsu
35	DMIA	Demand Management Innovation Allowance
36	DMIS	Demand Management Incentive Scheme
37	DMS	Distribution Management System
38	DNSP	Distribution Network Service Provider
39	DRMF	Distribution Reliability Management Framework
40	DRP	Debt Risk Premium
41	DSE	Victorian Department of Sustainability and Environment
42	DSPR	Distribution System Planning Report
43	DUOS	Distribution Use of Service
44	EBA	Enterprise Bargaining Agreement
45	EBSS	Efficiency Benefit Sharing Scheme
46	EDO	Expulsion Drop Out
47	EDPD	Electricity Distribution Price Determination
48	EDPR	Electricity Distribution Price Review
49	EIP	Environmental Improvement Plan
50	ELV	Electric Light Vehicle
51	EMSP	Electrical Safety Management Plans
52	EPA	Environmental Protection Authority
53	ESAA	Electricity Supply Association of Australia
54	ESCV	Essential Services Commission of Victoria
55	ESMS	Electricity Safety Management Scheme
56	ESV	Energy Safe Victoria
57	ETSA	ETSA Utilities
58	EWP	Elevated Work Platform
59	GAAR	Gas Access Arrangement Review
60	Gartner	Gartner Inc.
61	GIS	Geographic Information System
62	GSL	Guaranteed Service Level
63	GSP	Gross State Product
64	GWh	Gigawatt Hour
65	HBRA	Hazardous Bushfire Risk Areas
66	HEH	Hong Kong Electric Holdings Ltd
67	HEI	HongKong Electric International Limited
68	HI	Health Index

ID	Abbreviation	Description
69	HV	High Voltage
70	IT	Information Technology
71	KPI	Key Performance Indicators
72	kV	Kilovolts
73	kVA	Kilovolt Amperes
74	LGA	Local Government Areas
75	LLV	Large Low Voltage
76	LV	Low Voltage
77	MAIFI	Momentary Average Interruption Frequency Index
78	MCE	Ministerial Council for Energy
79	MCR	Marginal Cost of Reinforcement
80	MDS	Metering Data Services
81	MEC	Major Electricity Company
82	MEPS	Minimum Energy Efficiency and Performance Standards for appliances
83	MRET	Mandated Renewable Electricity Target
84	MRIM	Manually Read Interval Meters
85	MRP	Market Risk Premium
86	MSATS	Market Settlement and Transfer Solution
87	MVA	Megavolt Ampere
88	MW	Megawatts
89	MWh	Megawatt Hour
90	NEL	National Electricity Law
91	NEM	National Electricity Market
92	NEMMCO	National Electricity Market Management Company Limited
93	NIEIR	National Institute of Economic and Industrial Research
94	NMI	National Metering Identifier
95	NPV	Net Present Value
96	NSW	New South Wales
97	OHS	Occupational Health and Safety
98	ORG	Office of the Regulator General
99	PABX	Private Automated. Branch Exchange
100	PAPL	Permitted Attached Private Lines
101	PB	Parsons Brinckerhoff
102	PDM	Program of Demand Management
103	Plan	Electric Line Clearance Management Plan
104	Plan	CitiPower's Melbourne CBD Security of Supply Plan, 16 June 2008

ID	Abbreviation	Description
105	Planning Guidelines	CitiPower's Network Augmentation Planning Policy and Guidelines (Planning Guidelines)
106	PNS	Powercor Network Services
107	PoE	Probability of Exceedance
108	POEL	Private Overhead Electric Line
109	PoF	Probability of Failure
110	PTRM	Post Tax Revenue Model
111	PV	Present Value
112	PV	Photovoltaic
113	PWC	PricewaterhouseCoopers
114	RAB	Regulatory Asset Base
115	RBA	Reserve Bank of Australia
116	RCM	Reliability Centred Maintenance
117	RECs	Renewable Energy Certificates
118	RET	Renewable Energy Target
119	RIN	Regulatory Information Notice
120	RIT-D	Regulatory Investment Test – Distribution
121	ROLR	Retailer of Last Resort
122	RTS	Richmond Terminal Station
123	Rules	National Electricity Rules
124	SAIDI	System Average Interruption Duration Index
125	SAIFI	System Average Interruption Frequency Index
126	SCADA	Supervisory Control and Data Acquisition
127	SCONRRR	Steering Committee on National Regulatory Reporting Requirements (SCONRRR)
128	SECV	State Electricity Commission of Victoria
129	SEPPs	State Environment Protection Policies
130	Silk Telecom	Silk Telecom Pty Ltd (ACN 095 420 616)
131	SKM	Sinclair Knight Merz
132	SOO	Statement of Opportunities
133	SoRI	Statement of Regulatory Intent
134	SoS	Security of Supply
135	STPIS	Service Target Performance Incentive Scheme
136	SWER	Single Wire Earth Return
137	TCPR	Transmission Connection Planning Report
138	TMR	Trunk Mobile Radio
139	TNSP	Transmission Network Service Provider

ID	Abbreviation	Description
140	TUoS	Transmission Use of System
141	URD	Underground Residential Distribution Systems
142	USAIDI	Unplanned System Average Interruption Duration Index
143	VCR	Value of Customer Reliability
144	VEECs	Victorian Energy Efficiency Certificates
145	VEET	Victorian Energy Efficiency Target
146	VF	Voice Frequency
147	VoIP	Voice over Internet Protocol
148	WACC	Weighted Average Cost of Capital
149	WMPs	Waste Management Policies
150	WMTS	West Melbourne Terminal Station

1. GENERAL

This Chapter addresses specific requirements of the National Electricity Rules (**Rules**) and the Australian Energy Regulator's (**AER**) Regulatory Information Notice (**RIN**) and details how the remainder of this Regulatory Proposal is structured.

1.1 Information provision

1.1.1 Regulatory Proposal compliance with Rules

This Regulatory Proposal is made in accordance with the requirements of Chapter 6 and Chapter 11 of the Rules. In particular, it:

- is submitted to the AER by 30 November 2009, which is 13 months before the expiry of the current distribution determination, as required under clause 6.8.2(b) of the Rules; and
- includes the following elements as required under clause 6.8.2(c) of the Rules:
    - a Classification Proposal – this is set out in Chapter 3 of this Regulatory Proposal;
    - a Building Block Proposal for Standard Control Services – this is set out in the information contained between Chapters 4 and 17 of this Regulatory Proposal;
    - a demonstration of the application of the control mechanism, and the necessary supporting information, for Alternative Control Services – this is set out in Chapter 23 of this Regulatory Proposal;
    - indicative prices for Direct Control Services for each year of the regulatory control period – this is set out in Chapters 19 and 23 of this Regulatory Proposal;
    - a negotiating framework for Negotiated Distribution Services – this is set out in Chapter 24 of this Regulatory Proposal; and
    - details the parts of the Regulatory Proposal that CitiPower claims to be confidential – this is set out in Chapter 25 of this Regulatory Proposal.

1.1.2 Regulatory Proposal compliance with RIN's requirements

In accordance with clause 6.8.2(d) of the Rules, this Regulatory Proposal complies with the requirements of, and contains, or is accompanied by, the information required by, the RIN served on CitiPower Pty (**CitiPower**) by the AER under section 28F(1)(a) of the National Electricity Law (**NEL**) on 13 October 2009.

As required by paragraph 1.1(d) of the RIN, Chapter 29 of this Regulatory Proposal provides a table that references each response to a paragraph in Schedule 1 of the RIN and explains where it is provided in, or as part of, this Regulatory Proposal.

In responding to the AER's RIN, CitiPower does not admit to the validity of the AER's RIN. While CitiPower has endeavoured to comply with each requirement under the RIN, CitiPower reserves its rights with regards to the power of the AER to issue the RIN on the terms contained therein.

1.1.3 Building Block Proposal compliance with Rules

As required by clause 6.3.1(c)(1) of the Rules, the Building Block Proposal that is included in this Regulatory Proposal has been prepared in accordance with the Post Tax Revenue Model, a Roll Forward Model, other relevant requirements of Part C of Chapter 6 and clause Schedule 6.1 of the Rules. Relevantly, the Building Block Proposal:

- is prepared in accordance with the building block approach detailed in clauses 6.4.3 and 11.17.2 of the Rules;
- addresses the requirements of clause 6.5.6 of the Rules in relation to forecast operating expenditure;
- addresses the requirements of clause 6.5.7 of the Rules in relation to forecast capital expenditure;
- includes an X factor that conforms with the requirements of clause 6.5.9 of the Rules;
- relates only to Standard Control Services, as required by clause 6.8.2(c)(2) of the Rules;
- contains the information and matters relating to capital expenditure detailed in clause S6.1.1 of the Rules;
- contains the information and matters relating to operating expenditure detailed in clause S6.1.2 of the Rules; and
- contains the additional information and matters detailed in clause S6.1.3 of the Rules.

The table in Chapter 29 of this Regulatory Proposal details where these requirements have been met.

1.1.4 Building Block Proposal compliance with RIN's requirements

The Building Block Proposal that is included in this Regulatory Proposal complies with the requirements of, and contains or is accompanied by information required by, the RIN, as is required by clause 6.3.1(c)(2) of the Rules.

The table in Chapter 29 of this Regulatory Proposal details where these requirements have been met.

1.1.5 Regulatory templates

CitiPower has completed the regulatory templates at Appendix A of the RIN, as required by paragraph 1.1(a) of the RIN **(Regulatory Templates)**. CitiPower has also completed a second set of the regulatory templates at Appendix A of the RIN, as required by paragraph 2.2 (a) of the RIN, which reflects CitiPower's proposed service classification. The proposed Regulatory Templates apply the current classification of services until the end of the current regulatory control period and the proposed classification will take effect from 2011.

The completed Regulatory Templates have been provided to the AER with this Regulatory Proposal. CitiPower has amended the AER's Regulatory Templates. These changes, and the reasons for these changes, are set out in Attachment C0201.

The following tables in the Regulatory Templates have either been populated with values of zero for all fields or no information has been entered in the tables, because those tables are not relevant to CitiPower (ie because there is no relevant information to provide, or because the requested information is not within CitiPower's knowledge or control, and is not capable of being derived from other information that is within CitiPower's knowledge or control):

- Regulatory Templates 2.1, table 5: there are no relevant costs;
- Regulatory Templates 2.2, tables 7 and 10 (in relation to all regulatory periods) and tables 8 and 9 (in relation to the next regulatory period): there are no relevant costs;
- Regulatory Template 4.1, tables 2A, 2B, 2C and 2D: expenditure is reported on an activity basis and accordingly it is not possible to match expenditure against each regulatory instrument or obligation;
- Regulatory Template 4.4, table 2 (in relation to the next regulatory period): CitiPower is proposing that costs related to the Central Business District (**CBD**) Security of Supply Project be recovered through charges for standard control services in the next regulatory control period, and accordingly the sections of this table that relate to the next regulatory period are not relevant and have been populated with a value of zero;
- Regulatory Template 6.3, table 9 (in relation to 2010-2015): network maximum demand is not forecast, and accordingly CitiPower is not able to provide the requested information;
- Regulatory Template 6.3, table 13 (in relation to 2010-2015): weather adjustments are not forecast, and accordingly CitiPower is not able to provide the requested information;

- Regulatory Template 6.3, table 14 (in relation to 2001-2006): prior to 2006, there were incorrect terminal station maximum demands reported and temperature data for every terminal station was not available from the Bureau of Meteorology, and accordingly CitiPower is not able to provide the requested information;

- Regulatory Template 6.3, table 15: prior to 2005 there was no standard method for temperature correction. Records of temperature-corrected zone substation maximum demand only go back to 2006;

- Regulatory Template 6.3, table 16: weather adjustments for feeder maximum demand are not part of CitiPower's planning process and records are not kept of the requested information, and accordingly CitiPower is not able to provide the requested information;

- Regulatory Template 6.3, tables 17, 18, 19 and 20: these tables relate to forecasts published in Distribution Network Service Provider (**DNSP**) annual planning statements and other primary network planning documents, but no forecasts in relation to these matters were published in those documents and accordingly there is no information to provide;

- Regulatory Template 6.3, tables 22, 24, 26 and 28: these tables relate to forecasts submitted in DNSP proposals, but no forecasts have been submitted in relation to these matters and accordingly there is no information to provide;

- Regulatory Template 6.4, rows related to the corporate plan: CitiPower does not have a corporate plan and accordingly there is no information to provide;

- Regulatory Template 6.4, rows related to land and easement acquisition policies: CitiPower does not have any land and easement acquisition policies and accordingly there is no information to provide;

- Regulatory Template 6.4, rows related to other relevant plans, policies, procedures or strategies: CitiPower does not have any other relevant plans, policies, procedures or strategies and accordingly there is no information to provide; and

- Regulatory Template 6.7, table 13: CitiPower does not keep separate information in the format required recording the requested tax asset values of public lighting assets and is not able to derive that information from its records.

Where other Regulatory Templates contain fields with a value of zero, it indicates that there are no relevant costs/expenditure/information (as applicable).

1.1.6 Cost Allocation Method

In accordance with paragraph 1.1(b) of the RIN and clause 11.17.5(a) of the Rules, CitiPower has provided its proposed Cost Allocation Method with this Regulatory Proposal (see Attachment C0180).

1.1.7 Policies, strategies, procedures and consultants' reports

In accordance with paragraph 1.1(c) of the RIN, CitiPower has provided the AER with the policies, strategies, procedures and consultants' reports that it used, or relied upon, in preparing this Regulatory Proposal.

These documents are listed in Chapter 30 of this Regulatory Proposal.

1.2 Adjustments to Regulatory Accounts – review of procedures

Paragraph 1.2(a) of the RIN requires CitiPower to identify and explain where historical information differs from information provided in the regulatory templates.

Paragraph 1.2(b) of the RIN requires CitiPower to identify the annual amount of any movement in provisions that is provided in the regulatory templates for historical or estimated annual expenditure.

Paragraph 1.2(c) of the RIN requires CitiPower to provide information about any allocators that have been used to disaggregate information where historical information provided in the regulatory templates was not directly available from CitiPower's financial systems.

Attachment C0140 contains spreadsheets that identify where historical information provided in the regulatory templates differs from information provided to the Essential Services Commission of Victoria (**ESCV**) in accordance with Guideline No. 3, and explains each difference. These spreadsheets in Attachment C0140 also identify the annual amount of any movement in provisions that is provided in the regulatory templates for historical and estimated annual expenditure.

Attachment C0140 also contains spreadsheets that identify the allocators used by CitiPower where the historical information was not directly available from the financial systems of CitiPower and explains the allocators used, including how each allocator has been derived and applied. CitiPower notes for the purposes of paragraph 1.2(c)(i) of the RIN that its statutory reporting year commences on 1 January.

There are some differences between the historic capital and operating expenditure information provided in this Regulatory Proposal and the audited Regulatory Accounts submitted to the ESCV under Electricity Industry Guideline No.3 Regulatory Information Requirements (**EIG3**). The adjustments include:

- retention of related party margins in the 2007 and 2008 expenditure forecasts. CitiPower incurs margins under agreements with its suppliers and considers these costs have been efficiently and prudently incurred;
- adding back operating and capital expenditure liabilities paid from provisions and removing provision movements charged to operating and capital

expenditure[1]. The AER requires under Schedule 2 clause 1.1(b) that costs be presented on a cash basis;

- reallocation of some minor costs between metering and prescribed services to more closely reflect the nature of the activity underlying these costs. These adjustments have been:
  - subject to separate correspondence between the AER and CitiPower during the course of the AMI Price Review[2];
  - audited by Deloitte Touche Tohmatsu **(Deloitte)**; and
  - accepted by the AER in its October 2009 final determination entitled *Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications;*
- miscellaneous adjustments in 2001-02 so that expenditure is stated on a consistent basis with expenditure in the current regulatory control period; and
- removal of licence fees these are deemed pass-through for the current regulatory control period under clause 2.3.15 of the *Electricity Distribution Price Review 2006-10 Final Decision Volume 2 Price Determination.*

The expenditure forecasts are consistent with attached EIG3 (except for adjustments made to classification of services discussed in Chapter 3), the proposed Cost Allocation Method and accounting policies for statutory reporting. Whilst the expenditure forecasts are consistent with the current capitalisation policies of CitiPower, consideration is currently being given to aligning CitiPower and Powercor Australia's capitalisation policies from 2011.

Table 1.1 summarises the adjustments to CitiPower's operating expenditure as reported in the Regulatory Templates and Table 1.2 summarises the adjustments to its capital expenditure as reported in CitiPower's proposed Regulatory Templates for Standard Control services. Attachment C0063 provides a more detailed description and explanation of the adjustments.

[1] Provisions that are adjusted for CitiPower are: safety and maintenance, customer refunds, employee entitlements, doubtful debts, accident compensation, uninsured losses, stock writedown, environment and restructure. All provision adjustments are made to operating and maintenance expenditure except for employee entitlements which are allocated between operating and maintenance expenditure and capital expenditure.

[2] Refer Attachment C0001 email of 21 September 2009 from B. Cleeve (Powercor Australia and CitiPower) to L. Irlam (AER).

	$'000s (real 2010)							
	2001	2002	2003	2004	2005	2006	2007	2008
Regulatory Accounts	42,522	39,847	34,937	56,095	29,977	30,148	34,893	33,737

[redacted]

[redacted]								
Reported in proposed Regulatory Templates	36,687	24,632	34,430	51,655	39,793	30,196	32,460	30,892

Table 1.1: Adjustments to reported operating costs for Standard Control services

	$'000s (real 2010)							
	2001	2002	2003	2004	2005	2006	2007	2008
Regulatory Accounts	91,901	80,116	73,873	79,425	85,064	94,285	75,054	80,232
[redacted]								
Reported in proposed Regulatory Templates	88,608	77,941	71,470	78,287	82,009	94,102	79,684	84,621

Table 1.2: Adjustments to reported capital costs for Standard Control services

It should be noted that the reported expenditure, in CitiPower's proposed Regulatory Templates, provides the starting point for which CitiPower has determined its:

- actual operating expenditure for the purposes of calculating the efficiency benefit carry over for the current regulatory control period. These adjustment are discussed in Chapters 6 and 9 of this Regulatory Proposal; and

- actual capital expenditure for the purposes of the roll forward of the regulatory asset base and tax asset base to 31 December 2010. However, in establishing actual capital expenditure for the purposes of the roll forward of the regulatory asset base and tax asset base, metering expenditure has been included in 2005 since metering was classified as a prescribed service in 2005.

2. COMMENCEMENT AND LENGTH OF REGULATORY CONTROL PERIOD

Clause S6.1.3(13) of the Rules requires CitiPower's Building Block Proposal to contain the proposed commencement and length of the regulatory control period.

CitiPower proposes that the next regulatory control period:

- commence on 1 January 2011. This is the day after CitiPower's current regulatory control period ends; and
- be for a period of five years, so that the next regulatory control period would end on 31 December 2015.

3. CLASSIFICATION OF SERVICES

This Chapter details CitiPower's classification proposal for the next regulatory control period.

3.1 Classification proposal

Clause 6.8.2(c)(1)(i) of the Rules requires CitiPower to include a classification proposal in its Regulatory Proposal that shows how it considers its distribution services should be classified under the Rules.

CitiPower's proposed classification of services is set out in Table 3.1 below.

Service category	Direct control services		Negotiated services	Unregulated
	Standard control	Alternative control		
Network services	All 'standard' network services			
Connection services	- Connection and augmentation works for new connections - Auditing of design and construction - Specification and design enquiry - Temporary Supply Services - Location of underground cables - Covering of low voltage mains for safety reasons - Elective underground service where an existing overhead service exists - Fault level compliance service			
Metering services		Metering data provider services for un-metered supplies with type 7 installation		
Public lighting		Operation, repair, replacement and maintenance of CitiPower's public lighting assets	- New public lighting - Provision of watchman (security) lights	

Service category	Direct control services		Negotiated services	Unregulated
	Standard control	Alternative control		
			- Repair of watchman (security) lights on CitiPower assets - Alteration and relocation of DNSP public lighting assets	
Fee based services		- De-energisation - Re-energisation - Wasted attendance – not DNSP fault - Service truck visits - Supply abolishment - Fault response – not DNSP fault - Meter Investigation - Special Reading - PV Installation		
Quoted services		- Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets - Supply enhancement at customer request - Emergency recoverable works (ie emergency works where customer is at fault and immediate action needs to be taken by the DNSP) - Damage to overhead service cables caused by high load vehicles - High load escort – lifting overhead lines		

Service category	Direct control services		Negotiated services	Unregulated
	Standard control	Alternative control		
			- Reserve feeder	Re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh

Table 3.1: CitiPower's classification proposal

3.2 Justification of differences from proposed classification in AER's Framework and Approach Paper

Clause 6.8.2(c)(ii) of the Rules requires this Regulatory Proposal to include the reasons for any differences if the proposed classification differs from that suggested in the AER's *Final Framework and Approach paper for Victorian electricity distribution regulation CitiPower, Powercor, Jemena, SP AusNet and United Energy Regulatory control period commencing 1 January 2011* (**Framework and Approach Paper**).

In addition, paragraph 2.1 of the RIN requires CitiPower to explain:

- the reasons for any departure from the Framework and Approach Paper, including why the proposed classification is more appropriate; and
- how the treatment of the service will differ under the proposed classification compared to under the Framework and Approach Paper.

A comparison of Table 3.1 above, setting out CitiPower's proposed classification of services, to Table 2.3 in the AER's Framework and Approach Paper and the AER's lists of Fixed Fee Services and Quoted Services (set out on pages 50 and 54-55 respectively) discloses that CitiPower is proposing the changes detailed in Table 3.2 to the indicative classification of services detailed in the AER's Framework and Approach Paper.

Service	AER's indicative classification in Framework and Approach paper	CitiPower's proposed classification
Connection and augmentation works for new connections	Negotiated Distribution Services	Standard Control Service
Auditing of design and construction	Alternative Control Service – Quoted Service	Standard Control Service
Specification and design enquiry	Alternative Control Service – Quoted Service	Standard Control Service
Temporary supply services	Alternative Control Service – Fee Based Service	Standard Control Service
Location of underground cables	Alternative Control Service – Fee Based Service	Standard Control Service

Covering of low voltage mains for safety reasons	Alternative Control Service – Fee Based Service	Standard Control Service
Elective underground service where an existing overhead service exists	Alternative Control Service – Fee Based Service	Standard Control Service
Fault level compliance service	Not classified	Standard Control Service
Reserve feeder	Not classified	Negotiated Distribution Services
Provision of watchman (security) lights	Not classified	Negotiated Distribution Services
Repair of watchman (security) lights on CitiPower assets	Not classified	Negotiated Distribution Services
Meter investigation	Not classified	Alternative Control Service – Fee Based Service
Special reading	Not classified	Alternative Control Service – Fee Based Service
PV installation	Not classified	Alternative Control Service – Fee Based Service
Re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh	Alternative Control Service – Fee Based Service	Not regulated
Energisation of new connections	Alternative Control Service – Connection Service	Alternative Control Service – Fee Based Service
Damage to overhead service cables caused by high load vehicles	Alternative Control Service – Fee Based Service	Alternative Control Service – Quoted Service
High load escorts – lifting overhead lines	Alternative Control Service – Fee Based Service	Alternative Control Service – Quoted Service

Table 3.2: Differences between AER's indicative, and CitiPower's proposed, services classification

CitiPower also notes that it does not distinguish between temporary disconnection / reconnection services and other de-energisation and re-energisation services. Therefore, it proposes that temporary disconnection / reconnection services not be identified as a separate distribution service.

CitiPower sets out below an explanation of each of the differences detailed in Table 3.2 between the AER's proposed classification of services, set out in Table 2.3 of the AER's Framework and Approach Paper, and CitiPower's proposed classification of services.

3.2.1 Connection and augmentation works for new connections

In the Framework and Approach Paper, the AER states that its likely approach is to classify *'connection and augmentation works for new customer connections'* as a Negotiated Distribution Service.

3.2.1.1 Reasons for departing from the AER's proposed classification

CitiPower considers that there are good reasons for departing from the AER's proposed classification.

Firstly, the AER is required to classify *'services'*, but the proposed classification seeks to classify *'works'*. The classification of *'works'* is not permitted under the Rules. Instead, the AER must identify the relevant services that are provided to customers in relation to *'connection and augmentation works'* and then classify those services.

For example, clause 6.2.1 of the Rules provides that the AER is to classify *'distribution services'*. This classification is then used for a number of purposes under other provisions of the Rules, notably including the calculation of the Regulatory Asset Base (**RAB**). In particular, clauses 6.5.1(a) and S6.2.1(e) provide that all capital expenditure that relates to assets that are used to provide Standard Control Services will be rolled into the RAB. The calculation of the RAB does not depend on a classification of the relevant *'works'* or *'assets'*, but it depends on the classification of the *'services'* that those assets are used to provide.

For this reason alone, a departure from the approach in the Framework and Approach Paper of classifying *'connection and augmentation works'* is necessary and inevitable.

Secondly, the Framework and Approach Paper assumes that the current customer contribution arrangements in the ESCV's Guideline 14 will not apply to new works in the 2011-15 regulatory control period[3]. However, CitiPower understands that the Victorian Government has confirmed that this assumption is incorrect and that the ESCV's Guideline 14 will continue to apply. The continued existence of the ESCV's Guideline 14 is inconsistent with the classification of these services as Negotiated Distribution Services.

In particular, the ESCV's Guideline 14 limits the amount of the costs of providing these services that CitiPower can recover from the customer. It will not be possible for CitiPower to comply with the ESCV's Guideline 14 and also to comply with the requirements in the Negotiated Distribution Service principles in clause 6.7.1 of the Rules, which would require CitiPower to charge the customer the full costs incurred in providing the service.

Classification of these services as a Negotiated Distribution Service will also mean that CitiPower may be unable to recover the shortfall between the cost of providing the service and the maximum amount that can be charged to customers under the ESCV's Guideline 14. The Framework and Approach Paper states that classifying these services as a Negotiated Distribution Service means that DNSPs will be able to recover the full capital costs from customers rather than through Distribution Use of System (**DUOS**) charges. However, that will not be possible given that the ESCV's Guideline 14 will continue to apply. Accordingly, the service classification needs to be reconsidered to ensure that the shortfall can continue to be recovered through DUOS charges.

[3] See page 38 of the Framework and Approach Paper

For these reasons, the continued existence of the ESCV's Guideline 14 is a relevant factor that the AER must have regard to in accordance with clause 6.2.1(c)(4) of the Rules, and that factor means that the classification proposed in the Framework and Approach Paper is not appropriate.

3.2.1.2 Nature of *'connection and augmentation works'*

In the Framework and Approach Paper, the AER seeks to classify *'connection and augmentation works'* that are undertaken by a DNSP to facilitate the establishment of new customer connections. The AER does not describe the nature of these works in any detail. However, CitiPower understands that what is described in the Framework and Approach Paper as *'connection and augmentation works'* includes those works required to facilitate routine and/or non- routine new or modified connections (see, for example, the references to *'standard'* and *'non-standard' 'connection and augmentation works'* on p.41 of the Framework and Approach Paper).

In the Framework and Approach Paper, the AER would appear to proceed on the basis of an unstated presumption that, because *'connection and augmentation works'* occur at the time of establishing a new or modified connection and are required in order to establish that connection, the construction of those assets that comprise the works is a distribution service supplied by a DNSP to a customer.

However, *'connection and augmentation works'* do not, of themselves, constitute a distribution service that a DNSP supplies to a customer. Rather, the *'connection and augmentation works'* undertaken to facilitate routine or non-routine new or modified connections involve the bringing forward of an augmentation to the shared distribution network. They involve the construction or augmentation of assets comprising part of the distribution network that is used to supply network services (being the conveyance, and controlling the conveyance, of electricity through the distribution network) to customers including but not limited to the connecting customer. The AER itself recognises that the construction of shared network assets comprise distribution *'network services'*, both as the AER understands the term and as this term is defined in the Rules (see Framework and Approach Paper at p.31).

3.2.1.3 Separate classification of *'connection and augmentation works'* is neither required nor permissible

Where a new customer connection requires an augmentation to the distribution network, the assets that are constructed as part of that augmentation will be used by CitiPower to provide distribution network services. This fact is recognised by the AER in the Framework and Approach Paper (on p.38) where it notes that the operation and maintenance of those assets will be treated as a Standard Control Service.

The assets associated with such an augmentation will form part of the *'distribution network'* as defined in the Rules and the service provided by means of those assets will be a *'shared distribution service'* as defined in the Rules. These augmentation works do not constitute the provision of a separate identifiable service that is to be classified by the AER. These works are instead an element of the provision of distribution network services.

In the Framework and Approach Paper, the AER has classified distribution network services as Standard Control Services. As discussed in section 3.2.1.1 above, Chapter 6 of the Rules permits the classification of distribution services. It does not permit the classification of *'works'*. In particular, clause 6.2.1 provides that the AER is to classify *'distribution services'*.

In any event, there is no need for the AER to seek to separately classify the *'connection and augmentation works'* that are required due to a new customer connection as a separate service. Those works are simply part of the provision of distribution network services, which the Framework and Approach Paper has already classified as Standard Control Services. As explained above, where a new customer connection requires an augmentation to the distribution network, the assets that are constructed as part of that augmentation will be used by CitiPower to provide Standard Control Services. Accordingly, those assets will be rolled into CitiPower's opening RAB in accordance with clauses 6.5.1 and S6.2.1 of the Rules, which provide that capital expenditure that relates to assets that are used to provide Standard Control Services is to be rolled into the RAB in accordance with the DNSP's Cost Allocation Method.

The continued application of the ESCV's Guideline 14 will mean that CitiPower will recover a proportion of the costs of constructing these assets directly from customers. CitiPower's proposed Cost Allocation Method provides that any customer contributions under the ESCV's Guideline 14 will be deducted from the capital expenditure that is rolled into the RAB.

This approach will avoid any double-recovery of costs and is consistent with clause 6.21.2(3) of the Rules, the Cost Allocation Principles (in particular clause 6.15.2(5) of the Rules) and the Cost Allocation Guidelines (in particular clause 2.2.5(b)(4), which states that a DNSP may only recover the same cost once through the charges that it levies for its distribution services).

The approach is also consistent with the form of regulation previously applicable to the services for the 2006-10 regulatory control period.

3.2.1.4 Presumption in favour of prior classification or previously applicable regulatory approach

As recognised by the AER in the Framework and Approach Paper (at pp.30-31), clause 6.2.1(d) of the Rules requires the AER, in classifying a distribution service as a Direct Control Service or a Negotiated Distribution Service, not to depart from the previous classification or previously applicable regulatory approach unless a different classification is clearly more appropriate.

Against this background, the AER identifies *'connection and augmentation works'* as being excluded distribution services under the current arrangements for the regulation of distribution services in Victoria (in Table 2.1 and on p.36 of the Framework and Approach Paper). This is incorrect.

As disclosed by Part A of the Attachment to the 2005 Tariff Order (and the extract thereof set out in Appendix C to the Framework and Approach Paper), it is *'capital* *contributions for new works and augmentation'* [emphasis added] (and not *'connection and augmentation works'* themselves) that are excluded distribution services under the current arrangements in Victoria. The remainder of the capital expenditure incurred on *'connection and augmentation works'* is treated as a prescribed distribution service under the current arrangements.

For the reasons discussed above, under Chapter 6 of the Rules, it is not open to the AER to classify the capital contributions for new works and augmentations (that is, a portion of the costs of the works). The AER is required to classify distribution services, and not capital expenditure or works, with Chapter 6 then prescribing the treatment of the capital expenditure by reference to the classification of the services to which the expenditure relates.

CitiPower observes that Chapter 6 of the Rules and the AER's classification of network services as Standard Control Services together ensure that the regulatory treatment of capital expenditure on *'connection and augmentation works'* is the same as the treatment of that expenditure under the current arrangements in Victoria. The current form of regulation in Victoria allows CitiPower to recover a proportion of the costs of *'connection and augmentation works'* directly from customers under the ESCV's Guideline 14 and to roll the remainder of those costs into the RAB and recover them through DUOS charges. As discussed above, this regulatory approach will continue under Chapter 6 of the Rules, as a result of the AER's classification of network services as Standard Control Services in the Framework and Approach Paper in the absence of any discrete classification of *'connection and augmentation works'*. By contrast, classifying all *'connection and augmentation works'* as Negotiated Distribution Services would not be consistent with the previous regulatory approach because it would be likely to prevent CitiPower from continuing to recover a proportion of the costs from the customer under ESCV Guideline 14 and recovering the remainder of the costs from all users under DUOS charges.

3.2.1.5 Form of regulation factors

Clause 6.2.1(c)(1) of the Rules requires the AER to have regard to the form of regulation factors set out in section 2F of the NEL, in considering whether a different classification to that previously applicable is clearly more appropriate for the purposes of clause 6.2.1(d).

In the Framework and Approach Paper, the AER concludes that a consideration of the form of regulation factors, in accordance with clause 6.2.1(c)(1) of the Rules, supports the classification of *'connection and augmentation works'* as Negotiated Distribution Services. In particular, the AER concludes (at p.41) that *'standard'* and *'non-standard' 'connection and augmentation works'* should be classified as Negotiated Distribution Services because:

> *'-the market for these services is contestable and characterised by several participants in the market*
>
> *-the AER has assumed that the regulatory obligations applicable to DNSPs outlined above for the tendering of construction works (currently under the*

> *ESCV Guideline 14 and the DNSPs' licences) will continue in some form after 2010, and*
>
> *-there is no economic need for direct control regulation'.*

However, a review of the discussion of the form of regulation factors in the Framework and Approach Paper (at pp.36-39) discloses that it is the '*works*', rather than the distribution services to which they relate, that the AER has assessed against the form of regulation factors. It is the provision of the '*works*' that the AER concludes is currently contestable in Victoria and it is the '*works*' that it concludes are supplied by alternative providers that successfully tender to undertake them.

By their terms, however, the form of regulation factors are concerned with electricity network services (defined in section 2 of the NEL to mean '*a service provided by means of, or in connection with, a … distribution system*'). They require a consideration of:

> *'(a) the presence and extent of any barriers to entry in a market for <u>electricity network services</u>;*
>
> *(b) the presence and extent of any network externalities (that is, interdependencies) between <u>an electricity network service provided by a network service provider</u> and any other electricity network service provided by the network service provider;*
>
> *(c) the presence and extent of any network externalities (that is, interdependencies) between <u>an electricity network service provided by a network service provider</u> and any other service provided by the network service provider in any other market;*
>
> *[etc]' [Emphasis added].*

The application of the form of regulation factors to '*connection and augmentation works*' is, therefore, a misapplication of those form of regulation factors and inconsistent with the mandatory consideration prescribed by rule 6.2.1(c)(1) of the Rules.

The AER is correct in concluding that there is contestability in respect of the undertaking of '*connection and augmentation works*'. However, the assets that are constructed or augmented by those works are owned, operated and maintained by the relevant DNSP and the services provided by means of those assets are non-contestable. Thus, an application of the form of regulation factors to the services provided by means of the assets constructed or augmented by the works (that is, the network services provided by those shared distribution network assets) supports the classification of those services as Standard Control Services. The form of regulation factors cannot be construed as supporting the classification of '*connection and augmentation works*' as Negotiated Distribution Services.

3.2.2 Temporary supply services

The AER's Framework and Approach Paper proposed classifying the provision of temporary supply services as an Alternate Control Service.

CitiPower proposes that temporary supply services should be classified as Standard Control Services.

Presently CitiPower does not charge a fee for temporary supply services. Where connection is required on a temporary basis, a new connection fee is charged as from a Business perspective, the work effort involved is the same.

As such, the reasons CitiPower considers temporary supply services should be treated as Standard Control and how the treatment of the service will differ under the proposed service classification are the same as outlined above for connection and augmentation works for new connections.

3.2.3 Auditing of design and construction service and specification and design enquiry service

The AER's Framework and Approach Paper proposed classifying the auditing of design and construction service and the specification and design enquiry service as Alternative Control Services. The AER proposed grouping them as Quoted Services.

CitiPower proposes that these services should be classified as Standard Control Services. This is because these services are inextricably linked to the establishment of new or modified customer connections and to the payment of Customer Contributions by developers and customers to CitiPower.

Clause 6.2.2(c)(4) requires the AER to have regard to the desirability of a consistent regulatory approach to similar services (within, as well as beyond, the relevant jurisdiction) in classifying a Direct Control Service as either a Standard Control Service or an Alternative Control Service.

As is discussed in section 5.5 of this Regulatory Proposal, where CitiPower receives Customer Contributions for connection and augmentation works accordance with Guideline 14 then, in the current regulatory control period, these payments are netted off CitiPower's capital expenditure that is included in its RAB. CitiPower proposes that this treatment continue in the next regulatory control period.

Fees for auditing of design and construction services and specification and design enquiry services are inherently part of the customer connection process ie they form part of the process by which ownership of new or augmented assets constructed by a party other than CitiPower are transferred to CitiPower. They otherwise relate to the same new or modified connection and, accordingly, CitiPower submits that these services should be classified in the same manner as connection and augmentation works. CitiPower considers that this would ensure that there is no difference in the regulatory treatment of Customer Contributions and fees for auditing of design and construction services and specification and design enquiry services. They would both be netted off CitiPower's capital expenditure that is included in its Standard Control Services' RAB.

In addition, in the AER's Framework and Approach Paper (at p.56) in responding to Jemena's submission that the auditing of design and construction, and specification and design enquiry, services should be classified as Negotiated Distribution Services, the AER correctly observed that these services *'can only be provided by or on behalf of the DNSP'*. There is no scope for competition in the provision of the services. Accordingly, for the purposes of clause 6.2.2(c)(1) also, a Standard Control Service classification is to be preferred.

3.2.4 Energisation of new connections

The AER's Framework and Approach Paper proposes to classify the energisation of new connections as an Alternative Control Service.

CitiPower proposes that no discrete classification for the energisation of new connections is required, as the service of energising a new connection is indistinguishable from that of the de-energisation or re-energisation of existing connections and, thus, has the same characteristics as the services of de-energisation and re-energisation. In the alternative, if the AER is minded to retain a separate classification for the energisation of new connections, CitiPower proposes that the service of energisation of new connections should be grouped as a Fee Based Service, rather than as a Connection Service, for the purpose of its classification as an Alternative Control Service.

CitiPower's proposed approach is consistent with clause 6.2.2(c) of the Rules which provides that the AER must have regard to the desirability of a consistent regulatory approach to similar services, here energisation, de-energisation and re-energisation, in classifying Direct Control Services as Standard Control or Alternative Control Services. It is also consistent with:

- the AER's characterisation, in the Framework and Approach Paper, of services in the Fee Based Services grouping, as energisation of new connections (like de-energisation and re-energisation) is a service with a homogenous nature and scope and the costs of which can be estimated with reasonable certainty in advance; and
- CitiPower's current approach of charging a fixed fee for the energisation of new connections.

3.2.5 Location of underground cables

The AER's Framework and Approach Paper proposes classifying the location of underground cables as an Alternative Control Service and to treat them as Fee Based Service.

CitiPower proposes that this service should be classified as a Standard Control Service. This is because clause 6.2.2(d) of the Rules requires that, in classifying direct control services, the AER must not depart from a previous classification or previously applicable regulatory approach (unless a different classification *'is clearly more appropriate'*) and this service is currently included in CitiPower's *'prescribed distribution services'* costs.

A consideration of the national electricity objective discloses that a departure from the previous regulatory approach to the location of underground cables service cannot be justified and, indeed, would be wholly inappropriate.

Section 16(1) of the NEL requires that the AER, in performing or exercising an AER economic regulatory function or power, do so *'in a manner that will or is likely to contribute to the achievement of the national electricity objective'*. The national electricity objective set out in section 7 of the NEL, in turn, requires the AER to promote efficient investment in, and the efficient operation and use of, electricity services for the long term interests of consumers of electricity including with respect to the safety and reliability of supply and system reliability.

The classification of the *'location of underground cables'* service as a Standard Control Service will promote the long term interests of consumers of electricity with respect to the safety and reliability of supply, and system reliability.

The safety of the network is of paramount concern, as is recognised by the national electricity objective. This classification will promote the safety not just of the person seeking the location of the underground cable, but the community in general.

Since the commencement of the current regulatory control period, CitiPower has not charged a fee to persons seeking the location of underground cables. The decision to cease charging a fee followed a number of incidents where persons did not contact CitiPower prior to excavating in order to avoid paying a fee. This resulted in instances of cables being severed, which compromised the safety of those undertaking the excavations and the community as well as affecting system reliability.

As such, CitiPower believes the long term interests of customers are best served by individuals not being charged for CitiPower locating underground assets. The costs of providing this service should be recovered through distribution use of system tariffs.

3.2.6 Coverage of low voltage mains

The AER's Framework and Approach Paper proposes classifying the coverage of low voltage mains as an Alternative Control Service and to treat them as Fee Based Service.

CitiPower proposes that this service should be classified as a Standard Control Service. This is because clause 6.2.2(d) of the Rules requires that, in classifying direct control services, the AER must not depart from a previous classification or previously applicable regulatory approach (unless a different classification *'is clearly more appropriate'*) and this service is currently included in CitiPower's *'prescribed distribution services'* costs.

A consideration of the national electricity objective discloses that a departure from the previous regulatory approach to the coverage of low voltage mains cannot be justified and, indeed, would be wholly inappropriate.

Section 16(1) of the NEL requires that the AER, in performing or exercising an AER economic regulatory function or power, do so *'in a manner that will or is likely to contribute to the achievement of the national electricity objective'*. The national electricity objective set out in section 7 of the NEL, in turn, requires the AER to promote efficient investment in, and the efficient operation and use of, electricity services for the long term interests of consumers of electricity including with respect to the safety and reliability of supply and system reliability.

The classification of the *'coverage of low voltage mains'* service as a Standard Control Service will promote the long term interests of consumers of electricity with respect to the safety and reliability of supply, and system reliability.

The safety of the network is of paramount concern, as is recognised by the national electricity objective. This classification will promote the safety not just of the person seeking coverage of low voltage mains, but the community in general.

Since the commencement of the current regulatory control period, CitiPower has not charged a fee to persons seeking coverage of low voltage mains. The decision to cease charging a fee followed a number of incidents where persons did not contact CitiPower prior to operating large equipment in the vicinity of low voltage mains in order to avoid paying a fee. This resulted in instances of cables being damaged, which compromised the safety of those working with large equipment and the community as well as affecting system reliability.

As such, CitiPower believes the long term interests of customers are best served by individuals not being charged for CitiPower covering low voltage mains. The costs of providing this service should be recovered from all customers through distribution use of system charges.

3.2.7 Reserve feeder

The AER's Framework and Approach does not include a reserve feeder service. However CitiPower provides this service, which involves operating and maintaining a second source of supply to a customer's premise.

CitiPower considers that this service should be classified as a Negotiated Service for the purposes of clause 6.2.1 of the Rules. Treatment of reserve feeder as a Negotiated Service is appropriate as it relates to customers who are receiving a service above and beyond the minimum standards established in the *Victorian Electricity Distribution Code*. To that extent the costs of providing the service are directly attributable to the customer who is receiving the service.

It is important to note that the reserve feeder charge recovers only the operation and maintenance costs associated with the reserve feeder. A request for a new reserve feeder would be treated as for any other new connection under Electricity Industry Guideline 14.

3.2.8 Provision of watchman (security) lights

The AER's Framework and Approach Paper does not include provision of new watchman (security) lights as a service. CitiPower does, however, provide new watchman (security) lights on a customer request.

CitiPower considers this service should be classified as a Negotiated Service for the purposes of clause 6.2.1 of the Rules. Treatment of the provision of new watchman (security) lights as a Negotiated Service is appropriate as this service relates to customers who are receiving a service above and beyond the minimum standard of service generally provided by CitiPower. As the cost of providing this service is directly attributable to the customer who is receiving it, CitiPower considers that the customer should pay for this service.

It is also important to note that customers are able to seek the provision of watchman (security) lights from other parties other than CitiPower.

3.2.9 Repair of watchman (security) lights on CitiPower assets

The AER's Framework and Approach Paper does not include a repair of watchman (security) light installed on CitiPower assets as a service. CitiPower does, however, repair new watchman (security) lights on a customer request where it has been mounted on CitiPower assets.

CitiPower considers this service should be classified as a Negotiated Service for the purposes of clause 6.2.1 of the Rules. Treatment of the repair of new watchman (security) lights as a Negotiated Service is appropriate as this service relates to customers who are receiving a service above and beyond the minimum standard of service generally provided by CitiPower. As the cost of providing this service is directly attributable to the customer who is receiving it, CitiPower considers that the customer should pay for this service.

3.2.10 Metering investigation

In the AER's Framework and Approach Paper (at p.60), the AER states that it considers that its proposed classification, set out in Table 2-3 of the Paper:

> *'…are likely to cover the full spectrum of the DNSP's distribution services, other than:*
>
> - *meter provision services and metering data provision services for customers with annual consumption of 160MWh or more that are serviced by type 1 to 4 remotely read interval meters,*
> - *metering services provided to customers with annual consumption greater than 160MWh that have either type 5 manually read interval meters or type 6 manually read accumulation meters,*
> - *the metering services that will be regulated under the November 2008 AMI Order in Council, and*

- *the provision of watchman lights,*

which are not classified in this framework and approach paper.'

However, the AER would appear to have overlooked metering investigation services, which are neither the subject of the AER's proposed classification nor a metering service of the kind that the AER identifies as unclassified in the passage from the Framework and Approach Paper set out above. In particular, metering investigation services are not regulated under the AMI Price Review.

CitiPower provides a metering investigation service for connection points where requested to do so by a retailer. This request may be initiated either by the retailer itself or by a customer.

A metering investigation service is not regulated under the AMI Price Review but is a service that CitiPower currently provides. This service should therefore be regulated by the AER under its Distribution Determination and should be classified as a Direct Control Services and an Alternative Control Services for the purposes of clauses 6.2.1 and 6.2.2 of the Rules. For the purposes of service classification, it should be grouped as a Fee Based Service.

A metering investigation service should be classified as a Direct Control Service and an Alternative Control Service because:

- clauses 6.2.1(d) and 6.2.2(d) of the Rules require that, in classifying distribution services and direct control services, the AER must not depart from a previous classification or previously applicable regulatory approach (unless a different classification *'is clearly more appropriate'*); and
- a metering investigation service is currently treated as an Excluded Distribution Service by the ESCV.

In addition, classifying a metering investigation service as a Direct Control Service and an Alternative Control Service because:

- clauses 6.2.1(d) and 6.2.2(d) of the Rules require that, in classifying distribution services and direct control services, the AER must not depart from a previous classification or previously applicable regulatory approach (unless a different classification *'is clearly more appropriate'*); and
- a metering investigation service is currently treated as an Excluded Distribution Service by the ESCV.

In addition, classifying a metering investigation service as a Direct Control Service is appropriate, and thus a departure from the current treatment of this service cannot be justified for the purposes of clause 6.2.1(d), because:

- for the purposes of clause 6.2.1(c)(1) of the Rules and the form of regulation factors set out in section 2F of the NEL, CitiPower considers that there are:

  - high barriers to a new entrant competing with CitiPower to provide this service given the existing provisions of the Rules governing metering, the NEM Metrology Procedure, the *'B2B Procedure – Service Order Process'* and the *'B2B Procedure – Meter Data Process'*;

  - network externalities given that CitiPower can use factors of production that relate to its shared network to provide ancillary metering services. In particular, CitiPower can use the same assets, labour and materials to provide both its metering investigation service and its network services;

  - no real opportunities for customers to exert counter-veiling market power in respect of the provision of the metering investigation service;

  - no real competitive or substitution possibilities for this service given the regulatory framework under which it is provided;

- for the purposes of clause 6.2.1(c)(3) of the Rules, a metering investigation service is classified as a Direct Control Service in NSW for its 2009-10 to 2013-14 regulatory control period and the AER has proposed that the same classification be applied in Queensland for its 2010-11 to 2014-15 regulatory control period; and

- for the purposes of clause 6.2.1(c)(4) of the Rules, another relevant factor that the AER should consider in classifying the metering investigation service is that this service is currently provided by CitiPower, but is not regulated under the AMI Price Review.

Classifying the metering investigation service should be classified as an Alternative Control Service rather than a Standard Control Service is appropriate and thus a departure from the current treatment of this service cannot be justified for the purposes of clause 6.2.2(d) of the Rules, because for the purposes of:

- clause 6.2.2(c)(1) of the Rules, there is limited, if any, potential for the development of competition in provision of these services given the current regulatory framework that applies to this service;

- clause 6.2.2(c)(2) of the Rules, classifying metering investigation services as Alternative Control Services will minimise the administrative costs on CitiPower, the AER, users and potential users by virtue of continuing the current regulatory treatment in the next regulatory control period;

- clause 6.2.2(c)(3) and (4) of the Rules, as noted above, this classification is consistent with the treatment in NSW and the proposed treatment in Queensland; and

- clause 6.2.2(c)(5) of the Rules, the costs of providing a metering investigation service can be directly attributed to individual customers.

CitiPower considers that including the metering investigation service in the Fee Based Service grouping is appropriate because the service has the characteristics of a Fee

Based Service identified by the AER, in its Framework and Approach Paper (at p.50). Namely, metering investigation services are homogenous in nature and scope and, therefore, their costs can be estimated with reasonable certainty in advance of the provision of these services. For these reasons, CitiPower currently charges a fixed fee for metering investigation services.

3.2.11 Special reading (customer or retailer requested)

In the AER's Framework and Approach Paper, it would appear to have overlooked special reading services, which are neither the subject of the AER's proposed classification nor metering services of the kind that the AER identifies as unclassified in the Paper (at p.60).

The AER's Framework and Approach Paper did not classify most metering provider services as it considered that they were covered by the AMI Order in Council.

However, CitiPower provides meter investigations and special reading services at the request of customers and retailers, which are not covered by the AMI Order in Council:

- metering investigations involve investigating a connection point where a customer raises a request with their retailer to investigate a meter fault or the retailer has grounds to proceed with an investigation; and
- special readings involve retailer requesting CitiPower to perform an out of cycle reading that is not associated with a re-energisation or a de-energisation of an existing premises.

These services are not regulated under the AMI Order in Council and they should therefore be regulated by the AER under its Distribution Determination. CitiPower considers that they should be classified as a Direct Control Service and an Alternative Control Service for the purposes of clauses 6.2.1 and 6.2.2 of the Rules for the same reasons as detailed above for metering investigations. In particular, CitiPower notes that:

- it is the only party that can provide this service for Types 5 and 6 meters in its distribution area;
- the nature and scope of the works is similar between customers;
- the cost of providing the service can be estimated with reasonable certainty in advance;
- a generic price can be set for the service before the service is requested; and
- the service, and therefore the cost, can be attributed directly to an individual customer.

CitiPower considers that these services should be regulated as Fee Based Services.

3.2.12 Photovoltaic (PV) installation

The AER's Framework and Approach Paper does not include a photovoltaic installation service. However, CitiPower provides this service, which involves a customer requesting to connect an embedded generator to CitiPower's distribution network.

Different charges apply depending on the type of meter being installed, if the meter installation work is contestable or non-contestable and whether the service is provided during, or after, business hours.

CitiPower considers that this service should be classified as a Direct Control Service and an Alternative Control Service for the purposes of clauses 6.2.1 and 6.2.2 of the Rules for the same reasons as detailed above for metering investigations. In particular, CitiPower notes that:

- for electrical safety reasons it is the only party that can provide this service;
- the nature and scope of the works can be known with reasonable certainty in advance;
- the cost of providing the service can be estimated with reasonable certainty in advance;
- a generic schedule of prices can be set for the service before the service is requested; and
- the service, and therefore the cost, can be attributed directly to an individual customer.

CitiPower considers that these services should be regulated as Fee Based Services.

3.2.13 Elective underground service where an existing overhead service exists

The AER's Framework and Approach Paper states in relation to Alternative Control Services that are to be treated as Fee Based Services that:

> *'These services are generally homogenous in nature and scope and therefore their costs can be estimated with reasonable certainty. This means that a fixed fee can be set in advance for the provision of these services.'*[4]

The AER's Framework and Approach Paper proposes classifying *'Elective underground services where an existing overhead service exists'* as Alternative Control Services and to group them as Fee Based Services. CitiPower does not agree with this classification. This is because:

[4] AER, Framework and Approach Paper for Victorian Electricity Distribution Regulation, May 2009, page 50

- this is an *'above standard'* service, the nature and scope of which differs between customers;
- the cost of evaluating site conditions and providing the service cannot be estimated without first understanding the customer's individual needs. CitiPower's experience is that the costs of excavation or boring varies substantially depending on the type of soil; and
- an individual price must be set for the service after it has been requested in accordance with Guideline 14.

CitiPower considers that this service should be classified as a Standard Control Service because, for the purposes of:

- the form of regulation factors under clause 6.2.1(c)(1) of the Rules, these services are provided in accordance with Guideline 14 in the same manner as any other new connection; and
- clause 6.2.1(c)(2) of the Rules, this service is currently treated as a Prescribed Distribution Service by the ESCV in the same way as any other new connection service.

CitiPower's proposed classification would result in the costs involved in the provision of these services being included in new connections capital expenditure under Standard Control Services, and the revenues received from customers with respect to these services being included as customer contributions under Standard Control Services.

3.2.14 Fault level compliance service

This service relates to managing fault levels in the Melbourne CBD arising from the connection of embedded generation customers. It is predominantly driven by the desire of developers to have six star energy efficiency building ratings.

CitiPower proposes that its fault level compliance service be classified as a Standard Control Service and has therefore included the costs of complying with the Code in the next regulatory control period in its New Customer Connection capital expenditure forecasts. CitiPower proposes that its costs be recovered from embedded generators seeking parallel connection to the network with name plate ratings above 100kW through a per kW charge.

CitiPower notes that it is not seeking to impose charges in relation to the conveyance or transfer of electricity to embedded generators but rather to apply charges in respect of compliance with applicable network standards following connection.

CitiPower considers that classifying this service as a Standard Control Service is appropriate for the purposes of clause 6.2.2 of the Rules because:

- there is no potential for the development of competition in the market for this service, as CitiPower is responsible for the management of fault levels on the distribution network and must take action in order to maintain compliance (clause 6.2.2(c)(1) of the Rules);

- the works are coordinated by CitiPower in a manner that will minimise the administrative costs of compliance with the Code (clause 6.2.2(c)(2) of the Rules);
- it is consistent with the regulatory approach that applies to this service in the current regulatory control period where it is treated as part of CitiPower's prescribed distribution services, albeit that there is currently no explicit charge for the service (clause 6.2.2(c)(3) of the Rules);
- it will result in all connection-related services that are provided by CitiPower being classified as Standard Control Services (clause 6.2.2(c)(4) of the Rules); and
- the costs of managing fault levels in the Melbourne CBD relate to the connection of embedded generators generally, rather than specifically to an individual embedded generator. It is therefore more appropriate that this service be treated as a Standard Control Service than as an Alternative Control Service (clause 6.2.2(c)(5) of the Rules).

3.2.15 Re-test of types 5 and 6 metering installations for first tier customers with annual consumptions greater than 160MWh

The Framework and Approach Paper states that the AER's likely approach is to classify the service to re-test of types 5 and 6 metering installations for first tier customers with annual consumptions greater than 160MWh as an Alternative Control Service and to treat it as a Fee Based Service.

CitiPower does not agree with this proposed classification and considers that this service should not be regulated. This is because this service relates to large customers that can have type 1 to 4 meters installed by any metering provider. A competitive market therefore exists in relation to the provision of meters to these customers. There is therefore no need for the AER to regulate this service.

3.2.16 Damage to overhead service cables caused by high load vehicles

The AER's Framework and Approach Paper proposes classifying *'Damage to overhead service cables caused by high load vehicles'* as an Alternative Control Service and to group it as a Fee Based Service.

CitiPower considers that providing *'Damage to overhead service cables caused by high load vehicles'* should be classified, as the AER has proposed, as an Alternative Control Service. However, it should be grouped as a Quoted Service rather than a Fee Based Service. This is because the defining features of this service are that:

- the nature and scope of the works differs between events;

- the cost of providing the service cannot be estimated without first understanding the scope and nature of the works; and
- an individual price must be set for the service after the event.

In proposing that this service be grouped as a Fee Based Service in its Framework and Approach Paper and responding to a submission from SP AusNet that this service should be grouped as a Quoted Service, the AER observed (at p.52) that *'an important consideration for the AER'* was that *'[t]he AER understands that other DNSPs do charge for this service on a fixed fee basis'*. The AER's understanding is incorrect. CitiPower does not charge for this service on a fixed fee basis. To the contrary, it currently charges for this service on a quoted basis for the reasons set out above.

3.2.17 High load escort – lifting overhead lines

The AER's Framework and Approach Paper proposes classifying *'High load escort – lifting overhead lines'* as an Alternative Control Service and to group it as a Fee Based Service.

CitiPower considers that providing *'High load escort – lifting overhead lines'* should be classified, as the AER has proposed, as an Alternative Control Service. However, it should be grouped as a Quoted Service rather than a Fee Based Service. This is because the defining features of this service are that:

- the nature and scope of the works differs depending on the nature route that needs to be travelled;
- the cost of providing the service cannot be estimated without first understanding the scope and nature of the works; and
- an individual price must be set for the service after the event.

3.3 Second set of regulatory templates

Paragraph 2.2(a) of the RIN requires CitiPower to provide two sets of regulatory templates if its proposed service classification differs from the service classification in the AER's Framework and Approach Paper.

Because, as discussed in section 3.2 of this Regulatory Proposal, CitiPower is proposing a different service classification to that detailed in the AER's Framework Approach Paper, it has provided two sets of regulatory templates:

- one set of regulatory templates presents all historic and estimated information for the current and previous regulatory control period, and all forecast information for the next regulatory control period, based on the AER's service classification; and
- the other set of regulatory templates presents historic and estimated information for the current regulatory control based on the ESCV's current service

classification and presents all forecast information for the next regulatory control period based on CitiPower's proposed service classification.

These two sets of regulatory templates are provided as Attachments to this Regulatory Proposal.

For the purposes of paragraph 2.2(b) of the RIN, CitiPower confirms that it has not made changes to the second set of regulatory templates other than those changes arising because CitiPower's proposed service classification differs from the service classification in the AER's Framework and Approach Paper.

4. DEMAND, ENERGY AND CUSTOMER FORECASTS

This Chapter details CitiPower's forecasts of maximum demand, energy consumption and customer numbers for Standard Control Services for the next regulatory control period and addresses specific requirements of the Rules and the RIN.

As has been CitiPower's business practice for the last 14 years, it has engaged the National Institute of Economic and Industry Research (**NIEIR**) to prepare energy and customer forecasts for the purposes of this Regulatory Proposal. NIEIR was also requested to prepare maximum demand forecasts at a terminal station level to verify internally generated maximum demand forecasts.

The NIEIR was founded in 1984 as an independent economic research and consulting group serving clients in both the public and private sectors. Its clients include many of Australia's largest and most dynamic corporations as well as Federal, State and Local Government. NIEIR has significant experience in electricity forecasting. Its clients include most transmission and distribution service providers in the National Electricity Market including VENCorp and AEMO. NIEIR's experience and track record provides CitiPower with the assurance that the forecasts prepared by NIEIR are reliable and robust.

4.1 Summary of demand forecasts for 2011-15

Clause S6.1.1(3) of the Rules requires CitiPower to include in its Building Block Proposal a forecast of its maximum demand (load) growth used in preparing its capital expenditure forecasts for the 2011-15 regulatory control period. This forecast is summarised in Table 4.1, together with forecasts of energy consumption and customer numbers.

	2011	2012	2013	2014	2015
Maximum demand (MW)[5]	1,535	1,577	1,619	1,661	1,705
Energy consumption (GWh)	6,030	6,046	5,944	5,828	5,836
Customer numbers	316,243	321,189	324,686	328,584	334,914

Table 4.1: CitiPower demand and customer forecasts for 2011-15

Regulatory Template 6.3 provides a detailed breakdown of CitiPower's historic and forecast maximum demand, energy consumption and customer numbers.

CitiPower has used its forecast of:

- maximum demand to prepare its Reinforcement capital expenditure forecasts and, the scale escalator that has been applied to its operating expenditure forecasts;

[5] Summation of non-coincident zone substation maximum demands

- energy consumption in applying the control mechanism and setting prices for Standard Control Services; and

- customer numbers to prepare its New Customer Connection capital expenditure forecasts and the scale escalator applied to its operating expenditure forecasts and the scale escalator applied to its operating expenditure forecasts.

The maximum demand and customer number forecasts are identified as key assumptions in preparing the capital expenditure forecasts in Chapter 5 of this Regulatory Proposal.

4.2 Maximum demand forecasts for 2011-15

CitiPower internally prepares annual maximum demand forecasts in megawatts (**MW**). It verifies the validity of its internal forecasts by cross-checking them against load forecasts prepared at the terminal station level by the independent consultant, the National Institute of Economic and Industrial Research (**NIEIR**), and the Australian Energy Market Operator (**AEMO**).

4.2.1 Methodology used to prepare maximum demand forecasts

Paragraphs 11.1(a) and 11.2(a) of the RIN require CitiPower to describe and explain the methodology it has used to prepare its maximum demand forecasts. In describing its methodology, CitiPower has addressed paragraphs 11.2(c) to (i) of the RIN, which require specific information about the basis on which the maximum demand forecasts have been prepared.

CitiPower prepares a bottom up, rolling ten year maximum demand forecast for each terminal station and zone substation, and a rolling five year N-1 maximum demand forecast for each sub transmission line.

The ten year maximum demand forecasts for each terminal station and zone substation firstly involves adjusting the most recent actual summer and winter daily maximum load data[6], at the zone substation level, to the corresponding 50th percentile Probability of Exceedance (**PoE 50**)[7].

Summer and winter PoE 50 maximum demand forecasts are then determined, on a rolling year by year basis, by:

- applying summer and winter demand growth rates, applicable to each area, to the zone substation PoE 50 adjusted maximum demands. The growth rates are based on historic, temperature adjusted, summer and winter load growth, specific to each zone substation area;

- adjusting for known block customer load increases and decreases. These are factored into the forecast at the respective distribution feeder and zone substation levels in the year that they are planned to occur; and

[6] The most recently available peak load data is 2008-09 for summer and 2008 for winter.
[7] This means that, on average, demand for electricity will exceed the forecast in one out of two years.

- adjusting for known load transfers, such as a transfer of load from a distribution feeder or zone substation that is at capacity to an adjacent distribution feeder or zone substation with spare capacity.

The PoE 50 peak demand forecasts for each zone substation are then aggregated up to each respective terminal station, taking into account the diversity and power factor.

The five year N-1 maximum demand forecast for sub-transmission lines is determined using load flow analysis software. The sub-transmission network, including sub-transmission lines, cables and zone substations, is modelled, with the relevant zone substation maximum demand forecasts incorporated into the model. Load flow analysis is then performed, under different scenarios, whereby sub-transmission lines are brought in and out of service to generate a maximum load forecast for each sub-transmission line under an N-1 situation.

CitiPower's approach to forecasting maximum demand is consistent with the industry standard spatial demand forecasting methodology. This involves a linear extrapolation of the trend between recently measured maximum demands to forecast future maximum demand whilst taking into account specific spot load impacts. Spatial demand forecasting has been adopted because demand in a particular region, and therefore the capacity requirements of infrastructure in that region, need not necessarily correlate to overall demand growth.

CitiPower confirms that, for the purposes of:

- paragraph 11.2(c) of the RIN, it does not prepare its load demand forecast on the basis of a particular base year. Rather, it uses the most recent PoE 50 temperature adjusted summer and winter maximum demand;

- paragraph 11.2(d) of the RIN, it prepares its demand forecasts based on a PoE 50;

- paragraph 11.2(e) of the RIN, it does not use any externally sourced software models to prepare its maximum demand forecasts. Rather, it uses its own internally developed models, which use Excel spreadsheets. The key assumptions and inputs used by these spreadsheets are detailed in section 4.2.2 below;

- paragraph 11.2(f) of the RIN, it uses a bottom up, rather than a top down, forecasting process by virtue of the forecasts being prepared for each of the following elements of the distribution system: zone substation; sub transmission line and terminal station;

- paragraph 11.2(g) of the RIN, it applies a weather normalisation methodology in preparing its maximum demand forecasts in accordance with the methodology outlined above;

- paragraph 11.2(h) of the RIN, it applies spot load and load transfer adjustments in preparing its maximum demand forecasts in accordance with the methodology outlined above; and

- paragraph 11.2(i) of the RIN, it has used no appliance models in preparing its maximum demand forecasts. CitiPower observes that no assumptions regarding average customer energy usage are relevant to maximum demand forecasts.

4.2.2 Key assumptions and inputs used in preparing maximum demand forecasts

Paragraph 11.2(b) of the RIN requires CitiPower to detail the key assumptions and inputs used in developing its maximum demand forecasts.

The key inputs used by CitiPower to prepare the maximum demand forecasts include:

- the historical, temperature adjusted, summer and winter load growth by area;
- the most recently available temperature adjusted actual summer and winter maximum load data (MW);
- known customer spot loads; and
- known load transfers.

CitiPower does not explicitly make any policy related assumptions in preparing its maximum demand forecasts. However, it implicitly has regard for the Federal and Victorian Government policy framework that is assumed by NIEIR and AEMO when it cross-checks its forecasts, in order to ensure the relative consistency of its terminal station forecasts. The policy assumptions made by:

- NIEIR in preparing its forecasts are detailed in its report entitled *Electricity Sales and Customer Number Projections for CitiPower region to 2019;* and
- AEMO in preparing its forecasts are detailed in its report entitled *Terminal Station Demand Forecasts.*

These documents have been provided to the AER as attachments to this Regulatory Proposal.

4.2.3 Historical observations and different levels of aggregation

Paragraphs 11.3(a) and (b) of the RIN require CitiPower to explain how its forecasting methodology is consistent with, and has taken into account, historical observations and to demonstrate that the forecast data are consistent at different levels of aggregation.

As discussed in section 4.2.1, CitiPower prepares its ten year maximum demand forecasts by:

- adjusting the most recent actual summer and winter maximum load data, at the zone substation level, to obtain the PoE 50 maximum loads;
- scaling the zone substation PoE 50 maximum loads according to the historic *'underlying'* summer and winter load growth for each zone substation area;

- adjusting for known block customer changes and load transfers; and
- aggregating the zone substation maximum demand forecasts up to each respective terminal station, taking into account of diversity and power factor.

As discussed in section 4.2.1, CitiPower prepares its five year N-1 maximum demand forecast for sub-transmission lines by:

- modelling the sub-transmission network, incorporating the relevant zone substation maximum demand forecasts into the model; and
- performing load flow analysis, under different scenarios N-1 scenarios to generate a maximum load forecast for each sub-transmission line.

CitiPower's maximum demand forecasts are not necessarily consistent at different levels of aggregation, being:

- distribution feeder level;
- zone substation level;
- sub-transmission line level; and
- terminal station level.

This is because of diversity resulting from different customers demanding electricity at different times during the day. For example, commercial loads' peak demand usually occurs during the early afternoon, whilst residential loads usually peak in the early evening. Due to this diversity in demand:

- the distribution feeders from a zone substation will not all peak at the same time, hence the sum of their maximum demands will not equate to the sum of the maximum demand of the zone substation;
- the zone substations supplied by the same sub-transmission loop will also not peak at the same time, hence the sum of their maximum demands will not equate to the maximum demand of the sub-transmission loop; and
- the sum of the maximum demands of the sub-transmission loops will not equate to the maximum demand at the terminal station level.

4.2.4 Independent verification of internally prepared demand forecasts

Paragraphs 11.4 and 11.5(a) and (b) of the RIN require CitiPower to provide certain information in relation to the independent verification of its maximum demand forecasts.

CitiPower has not engaged an independent verifier to examine the forecasts and the reasonableness of the method, process and assumptions used in determining the forecasts. CitiPower nonetheless considers its forecasts, method, process and assumptions are reasonable, and sets out the reasons for this below.

CitiPower has engaged NIEIR to prepare maximum demand forecasts at the terminal station level. CitiPower uses NIEIR's forecasts to test and validate its internally developed forecasts. NIEIR's methodology is detailed in Attachment C0006.

CitiPower also annually compares its maximum demand forecasts at the terminal station level with those that have been prepared by AEMO. AEMO's methodology, and most recent forecasts, are detailed in its report entitled *Terminal Station Demand Forecasts 2009/10 to 2018/19.*

CitiPower seeks to understand and reconcile any significant differences between its internally prepared maximum demand forecasts and those prepared by NIEIR and AEMO. CitiPower makes appropriate adjustments to its forecasts where required.

CitiPower notes that it has not sought and therefore does not have within its possession, custody or control independent verification of the kind sought by paragraph 11.5 of the RIN.

4.2.5 Incorporation of maximum demand forecasts in the 2011-15 expenditure forecasts

Paragraph 11.5(c) of the RIN requires CitiPower to provide independent verification of how its maximum demand forecasts have been used in determining the capital and operating expenditure forecasts. As noted above, CitiPower has not sought such independent verification, but explains how its maximum demand forecasts have been used below.

CitiPower has used the maximum demand forecasts as a:

- direct input in preparing the Reinforcement capital expenditure forecasts for the 2011-15 regulatory control period. This is discussed in section 5.3 of this Regulatory Proposal; and
- indirect input in preparing the scale escalator that has been applied to CitiPower's operating expenditure forecasts in order to accommodate the effect of network growth. This is discussed in section 6.9.2 of this Regulatory Proposal.

4.3 Energy consumption forecasts for 2011-15

CitiPower's energy consumption forecasts for the period 2011-15 have been prepared by NIEIR as part of its annual independent study for CitiPower. NIEIR's most recent forecasts are set out in its report entitled *Electricity sales and customer number projections for the CitiPower region to 2020.*

4.3.1 Methodology used to prepare energy consumption forecasts

Paragraphs 11.1(b) and 11.2(a) of the RIN require CitiPower to describe and explain the methodology it has used to prepare its energy consumption forecasts. In describing its methodology, CitiPower has addressed paragraphs 11.2(c) to (i) of the RIN which require specific information about the basis on which the energy consumption forecasts have been prepared.

NIEIR applies a top down approach to developing CitiPower's energy consumption forecasts. It forecasts the economic outlook for Australia, Victoria and CitiPower's regional area to 2020. This is detailed in chapters 2 to 4 of NIEIR's report. The methodology that NIEIR applies, using its energy forecasting model, to prepare its energy consumption forecasts is detailed in section 5.1 of its report. It states that:

> *'This model effectively takes NIEIR's state forecast of gross state product (by industry) and disaggregates it into 11 statistical sub-divisions across Victoria and 31 Local Government Areas (LGAs) in Melbourne. As indicated in* [Figure 4-1] *the economic forecasts are consistent with NIEIR's national and state economic models.'*

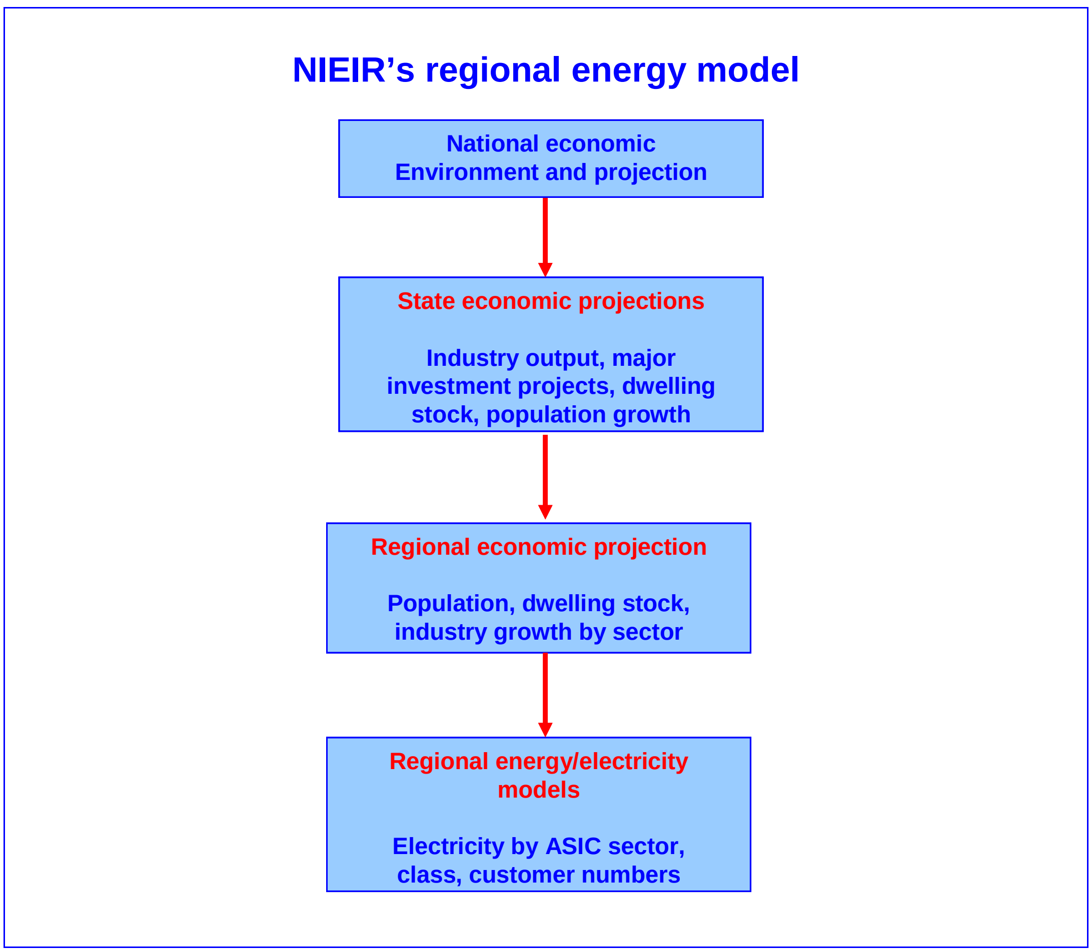

Figure 4-1: NIEIR's energy consumption forecasting model – regional energy model

NIEIR develops its forecasts of energy consumption on an industry basis for CitiPower's distribution area. It uses a regional energy consumption model, which has been parameterised using NIEIR's existing state electricity forecasting model. The model breaks customers into residential, commercial and industrial customer classes. It then applies the Australia Standard Industrial Classification (**ASIC**) to the commercial and industrial classes.

Regression models for each customer class link energy consumption by industry to real output growth by industry, electricity prices and weather conditions.

CitiPower confirms that, for the purposes of:

- paragraph 11.2(c) of the RIN, it is not aware of NIEIR using a particular base year for the reoppose of preparing energy consumption forecasts for the 2011-15 regulatory control period. CitiPower provided NIEIR with historical energy consumption data for 2000 to September 2009. NIEIR has applied this data in preparing its energy consumption forecasts for the next regulatory control period;

- paragraph 11.2(d) of the RIN, a probability of exceedance approach is not relevant to preparing energy consumption forecasts;

- paragraph 11.2(e) of the RIN, NIEIR's model has been used to prepare the energy consumption forecasts for the next regulatory control period. This is a proprietary model to NIEIR and CitiPower does not have access to it. Nonetheless, CitiPower sets out its understanding of the NIEIR model's key assumptions and inputs in section 4.3.2 below;

- paragraph 11.2(f) of the RIN, CitiPower understands that NIEIR's model applies a top down, rather than a bottom up, forecasting process;

- paragraph 11.2(g) of the RIN, NIEIR's model applies weather normalisation in preparing its energy consumption forecasts. The weather normalisation methodology applied by NIEIR is set out in its report entitled Electricity sales and customer number projections for the CitiPower region to 2020 which is provided at Attachment C0005 to this Regulatory Proposal;

- paragraph 11.2(h) of the RIN, CitiPower provides NIEIR for its consideration spot load and load transfer adjustments that it may choose to reflect into its model for the purposes of preparing the energy consumption forecasts. As the NIEIR model is a proprietary model, CitiPower is unable to outline the treatment of spot loads and load transfers in the energy consumption forecasting process; and

- paragraph 11.2(i) of the RIN, CitiPower is not aware of whether or not NIEIR's model incorporates appliance models given that it is a proprietary model and CitiPower only receives outputs from the model. CitiPower understands that NIEIR's model incorporates average customer energy usage assumptions. However, CitiPower is not privy to the specific nature of these assumptions.

4.3.2 Key assumptions and inputs used in preparing energy consumption forecasts

Paragraph 11.2(b) of the RIN requires CitiPower to detail the key assumptions and inputs used in developing its energy consumption forecasts. Paragraph 11.5(b) of the RIN further requires CitiPower to provide independent verification that the key input data are reasonable.

The key assumptions and inputs used by NIEIR in preparing its energy consumption forecasts include the macroeconomic indicator forecasts, which, taken together, form the economic outlook. NIEIR prepares forecasts at a national, State and CitiPower regional level for base, high and low growth scenarios for the period to 2020.

A summary of the Victorian, and CitiPower regional level, economic outlooks, and the associated relevant macroeconomic indicators, is set out below. CitiPower considers that these assumptions and inputs satisfy paragraph 11.5(b) of the RIN by virtue of being independently developed by NIEIR.

The Victorian economic outlook

The key State macroeconomic assumptions and inputs that have been incorporated into NIEIR's forecasting model are summarised in Table 4.2. These represent the base scenario to 2015.

Percentage change									
Macro-economic indicator	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	Compound growth rate 2008-09 to 2014-15
Private consumption	3.5	0.5	0.9	1.6	3.5	3.3	1.1	0.1	1.7
Private business investment	13.3	-6.6	-10.2	18.9	16.8	5.2	3.5	-5.1	4.3
Private dwelling investment	4.4	6.3	5.4	4.2	-6.3	-6.6	-1.5	12.1	1.0
Government consumption	2.6	2.9	3.4	3.6	1.9	2.0	3.8	3.4	3.0
Government investment	-11.5	21.0	25.3	2.2	17.2	-1.8	1.5	6.2	8.0
State final demand	4.5	0.5	0.6	4.6	5.3	2.6	1.9	0.5	2.6
Gross state product	3.2	-0.4	1.2	2.2	4.4	2.0	0.2	0.0	1.6
Population	1.8	1.7	1.5	1.3	1.2	1.1	1.2	1.2	1.2
Employment	2.7	1.4	-2.9	0.3	2.3	2.2	0.6	-0.6	0.3

Table 4.2: Victoria - macroeconomic aggregates and selected indicators

NIEIR has made the following assumptions in relation to the key macroeconomic indicators for the State of Victoria:

- Gross state product (**GSP**) – growth in the Victorian economy is expected to slow significantly in the 2008-09 to through to 2010-11 period. This is largely due to an expected fall in business investment and a decline in consumption expenditure growth. Economic growth is expected to start to strengthen by

2010-11 and is significantly stronger by 2011-12 before weakening again in 2012-13 due to a blow out in the current account deficit;

- Population – population growth has been a major driver of strong economic growth in Victoria over recent years. This is largely due to comparatively low net interstate migration losses, a natural increase in population growth and higher levels of net overseas migration. NIEIR forecasts that the Victorian population growth will however slow over the 2009-10 to 2014-15 period;

- Private consumption expenditure – private consumption expenditure growth has been an important determinant of Victorian GSP growth over recent years. In 2008-09, the collapse in financial markets and the associated impacts on consumer confidence led to a sharp deceleration in the rate of household spending growth in Victoria. NIEIR forecasts that the recovery in employment and income growth in 2011-12 will, however lead to an increase in private consumption expenditure in Victoria. Consumption expenditure growth is then forecast to weaken significantly in 2013-14 and 2014-15, partly reflecting high nominal interest rates, high levels of household debt, and weaker employment and income growth.

- Private business investment – private business investment in Victoria is projected to fall over the 2008-09 to 2009-10 period. This reflects the collapse in financial markets and the associated impact on consumer confidence. NIEIR expects a recovery in 2011-12, due to recovery in employment and income growth. This is followed by a weakening in consumption expenditure in 2013-14 and 2014-15 partly reflecting high nominal interest rates, high levels of household debt and weaker employment;

- Private dwelling expenditure – private housing construction expenditure in Victoria is forecast to remain strong over the period 2008-09 to 2010-11. This is supported by strong underlying demand growth, low nominal interest rates, and the Federal Government's First Home Owners Grant. Higher nominal interest rates by 2011-12 lead to a decline in private housing construction; and

- Government expenditure – the Victorian Government's long-term financial objectives are to maintain budget surpluses, to maintain net financial liabilities at prudent levels and to deliver strategic infrastructure projects to Victorians. Government investment is focussing on infrastructure assets (such as improving roads and transport) as well as redeveloping health and education facilities. Victorian Government investment expenditure is forecast to grow over the 2008-09 to 2011-12 period partly reflecting the Federal Government's stimulus package. Expenditure is expected to decline in 2012-13 before increasing again in 2014-2015.

CitiPower's regional economic outlook

CitiPower's distribution area covers the central Melbourne region and surrounding regions to the north, east and south. NIEIR has made the following assumptions in relation to the key macroeconomic indicators for CitiPower's region:

- Gross Regional Product – total gross regional product for CitiPower's region is forecast to grow by around 1.7 per cent per annum between 2009 and 2019. This is around 1.0 per cent below the forecast Victorian average growth rate over the same period, which is forecast to be around 1.8 per cent per annum. CitiPower's growth is largely driven by growth in Port Phillip, which is forecast to be around 4.1 per cent per annum over the 2009 to 2019 period. Melbourne is the largest region within the CitiPower distribution area and will average growth of around 1.5 per cent per annum over the period 2009 and 2019;

- Population – NIEIR forecasts that population growth in CitiPower's region will increase by an average rate of 0.9 per cent per annum between 2009 and 2019. On average, population growth in CitiPower's region is 0.3 per cent per annum below the Victorian population projection of 1.2 per cent per annum over the 2009 to 2019 period. The strongest areas of population growth in CitiPower's distribution area are Melbourne and Yarra which are forecast to increase by an average rate of 2.2 per cent per annum and 0.8 per cent per annum respectively; and

- Dwelling Stock – the total dwelling stock in CitiPower's distribution area is projected to grow by an average rate of 1.9 per cent per annum between 2009 and 2019. This represents approximately 62,000 dwelling units. The forecast growth in dwelling stock in CitiPower's distribution area is just above the projected growth rate for Victoria and reflects existing development and new apartments within CitiPower's distribution area. The strongest growth in the dwelling stock in CitiPower's distribution area between 2009 and 2019 is expected to occur in:

  - Melbourne with average growth of 4.0 per cent per annum between 2008 and 2018. This reflects the continued apartment construction within and around the CBD; and

  - The Port Phillip region with average growth of 1.3 per cent per annum over the same period.

NIEIR makes a number of assumptions in preparing its energy consumption forecasts about the nature, and likely effect of, Federal and State Government energy related policies. These policies mainly relate to climate change and energy efficiency and are designed to reduce energy consumption and to improve energy efficiency and thereby to reduce greenhouse gas emissions. CitiPower considers that these assumptions satisfy paragraph 11.5(b) of the RIN by virtue of being independently developed by NIEIR.

Energy Policy	2011	2012	2013	2014	2015
MEPs-lighting (GWh)	(47.1)	(58.54)	(60.29)	(57.46)	(59.74)
MEPS-Air Cond (GWh)	(1.11)	(1.68)	(2.31)	(2.72)	(3.1)
Standby power (GWh)	(3.51)	(7.67)	(8.96)	(8.1)	(7.2)
Insulation (GWh)	(5.14)	(2.57)	0	0	0
Photovoltaics (GWh)	(0.47)	(0.47)	(0.42)	(0.33)	(0.24)

VEET (GWh)	(2.08)	(2.08)	(2.08)	(2.6)	(1.56)
Hot water (GWh)	(1.04)	(1.02)	(0.84)	(0.76)	(0.74)
Hot water - off peak(GWh)	(4.27)	(5.98)	(7.69)	(9.4)	(11.11)
6 star building standards (GWh)	0	(0.16)	(0.32)	(0.29)	(0.29)
AMI (GWh)	(18.44)	(53.85)	(76.61)	(71.69)	(58.61)
Electric cars (off peak)	1.96	2.75	3.53	4.32	5.11
Total	-81.2	-131.27	-155.99	-149.03	-137.48

Table 4.3: Annual policy impacts on total energy consumption in the CitiPower distribution region

The following provides a discussion of how NIEIR has assumed certain key Federal and State Government energy related policies will apply in the next regulatory control period:

- Minimum Energy Efficiency and Performance Standards for appliances (**MEPS**) - the MEPS program is a federal initiative which was introduced in 1999. It is currently being progressively extended to cover a broader range of appliances and is also being made more stringent, thereby reducing electricity energy use per appliance.

  MEPS arrangements that are currently in force have had some influence on the level of CitiPower's energy sales in recent years and thus have been included in the base energy forecasts. Due to the relatively long life of many domestic appliances, these existing MEPS will continue to drive further sales reductions in the upcoming regulatory control period as appliance stock is turned over.

  The introduction of some new or amended MEPS are likely to materially influence sales forecasts over the 2011-15 regulatory control period, particular for lighting and air-conditioning. On this basis, NIEIR has sought to quantify their impact on energy consumption over this period and has reflected this in the energy consumption forecasts.

  - MEPS for lighting – this is due to be introduced in November 2009. Once it is introduced, most incandescent light globes (general service lamps) and some low voltage halogen lights, including down-lights and reflector bulbs, will no longer be available for purchase. The MEPS will initially be set at a minimum of 15 lumens per watt – incandescent light globes are about seven lumens per watt;

  - MEPS for air conditioning – the demand for air conditioning units has increased by around 10 per cent per annum over the past decade. In 2008, around 70 per cent of households reported having at least one space cooler. Air conditioner MEPS for the most common residential air conditioning units, reverse cycle all phases, will increased by around 9 per cent in 2010;

- Standby power – standby power accounts for about 11 per cent of electricity use in Australian households. The current average standby power of appliances is around four watts. By 2012, the standby target will be reduced to around one watt for all electrical appliances and equipment;

- Insulation program – this is a Federal Government program which provides a rebate of up to $1,600, over the 2009-2012 period, for the installation of insulation in ceilings, which are currently not insulated;

- Photovoltaics – small scale photovoltaic installations are now supported by a number of Federal and State Government incentives and this, together with decreasing unit costs, is leading to a substantial increase in their deployment in the residential sector. These incentives include photovoltaic feed in tariffs which commenced on 1 November 2009 and availability of Renewable Energy Certificates (**RECs**) under the mandatory renewable energy target (**MRET**)

- Victorian Energy Efficiency Target (**VEET**) – Phase one of the VEET initiative commenced on 1 January 2009 and is due to expire at the end of 2011. The target for phase one is 2.7 Mt CO_2e of deemed greenhouse gas abatement per year. VEET requires most electricity and gas retailers in Victoria to create or purchase and then acquit Victorian Energy Efficiency Certificates (**VEECs**) (denominated in tCO_2e) in proportion to their share of greenhouse gas emissions of total annual residential emissions in Victoria.

  Various categories of activities are specified as prescribed activities under the VEET phase one regulations. These include:

  - water heating – decommissioning of low efficiency water heating products and the installation of high efficiency water heating products. This also includes the installation of solar pre-heaters or solar retrofit kits;

  - space heating – decommissioning of low efficiency ducted heating products and the installation of high efficiency ducted heating products, and the installation of high efficiency space heating products;

  - space conditioning – installation of insulation, thermally efficient windows and weather sealing products;

  - lighting – installation of low energy lamps; and

  - refrigerators/freezers – purchase of high efficiency refrigerator or freezer (refrigerator purchase) and destruction of pre-1996 refrigerator or freezer (refrigerator destruction).

- Hot water - there are a number of initiatives that will affect electric water heating over the period to 2019. These include:

  - the Ministerial Council on Energy's (**MCE**) intention, foreshadowed in December 2008, to phase-out conventional electric resistance water heaters. This would apply to new and established homes in gas reticulated areas from 2010. It would also apply to new flats and apartments and established homes in gas non-reticulated areas from 2012. At the time of preparing this Regulatory Proposal, the MCE had not finalised its policy on this matter;

- a Federal rebate of $1,600 to replace electric resistance water heaters with solar water heaters (solar gas in gas areas) until 2013. Either this rebate, or the Federal insulation rebate, can be taken up by a household. There is also a rebate available for landlords to replace electric resistance water heaters;
- various rebates are administered by Sustainability Victoria, in relation to the installation of solar hot water or heat pumps and replacement of peak electric water heaters with high efficiency gas water heaters;
- the Victorian five star building standard, which requires the installation of a solar water heater or a plumbed water tank in new residences;
- hot water management, particularly regulations and incentives for installation of low flow shower heads; and
- Carbon Pollution Reduction Scheme (**CPRS**) impacts on electricity prices.

NIEIR forecast the likely impact on electricity sales arising from the various hot water initiatives by making explicit assumptions regarding replacement rates, replacement choices and the take-up of hot water by new customers.

- six star building standards - the Victorian Government's five star rating scheme for new homes that is managed by Sustainability Victoria, which has been in effect since 2005 is a key feature of the Victorian Government Greenhouse Policy. These standards require all new homes in Victoria to include a greater range of energy efficiency and water saving features. The five star rating was extended to cover all renovations and extension from May 2008.

  Through the Council of Australian Governments, all Federal, State and Territorial Governments have agreed to move towards a six star residential standard by 2012. The six star standard will include additional and amended standards including in relation to lighting, water heating and fixed equipment such as space heating and cooling.

- AMI - the Victorian Government has mandated that Advanced Metering Infrastructure (**AMI**) be rolled out to all customers consuming less than 160MWh of electricity per annum between 2009 and 2013. Under the AMI program, 2.9 million new *'smart'* meters will be installed over this period in Victoria with approximately 0.3 million to be installed by CitiPower. These new AMI meters will replace existing type 5 meters (manually read interval meters) and type 6 meters (manually read accumulation meters).

  The Victorian Government's overall objective of the AMI rollout is to allow Victorian consumers to better manage their energy use by providing improved price signals and more detailed time of use consumption information. This will, in turn, allow customers to better manage their demand for peak power and thereby save money and reduce greenhouse gas emissions.

- electric cars – Currently very few electric cars are in use in Victoria, but there is interest in assessing their potential and the Victorian Department of Transport is currently conducting a study on their use. In June 2009 Mitsubishi launched its Australian campaign for sales of its iMiEV ELV.

4.3.3 Other considerations

NIEIR has taken into consideration both the MRET and CPRS schemes in preparing its forecasts.

The expanded national MRET Scheme has been designed in cooperation with state and territory governments through the Council of Australian Governments. The national Renewable Energy Target scheme will increase the existing MRET by more than four times to 45,000 gigawatt-hours by 2020.

It will also provide an incentive to accelerate uptake of Australia's renewable energy sources and bring existing state-based targets into a single, national scheme.

The Australian Government is also introducing the Carbon Pollution Reduction Scheme (**CPRS**) to provide incentives to reduce greenhouse gas emissions by setting a carbon price. The CPRS will help bring renewable technologies into the market over time. As a transitional measure, the national MRET scheme will accelerate deployment of renewable energy technologies by providing a guaranteed market for renewable energy. The MRET will conclude in 2030, at which time the CPRS is expected to be the primary driver of renewable energy.

CPRS will lead to increases in electricity prices. In NIEIR's base case scenario, it has assumed the Federal Treasury's CPRS-5 scenario applies out to 2015.

4.3.4 Historical observations

Paragraph 11.3 of the RIN requires CitiPower to explain how its forecasting methodology is consistent with, and has taken into account, historical observations and how the resulting forecasts are consistent at different levels of aggregation.

As noted above, CitiPower provided NIEIR with historical energy consumption data for the period 2000 to September 2009. NIEIR has applied this data in preparing its energy consumption forecasts for the next regulatory control period.

On this basis, CitiPower considers that NIEIR's forecasts are consistent with, and take into account, historical observations.

The NIEIR forecasts are not prepared at different levels of aggregation and, thus, CitiPower is unable to comment on the consistency of NIEIR's energy consumption forecasts at different levels of aggregation.

4.3.5 Independent verification of energy consumption forecasts

Paragraphs 11.4 and 11.5(a) and (b) of the RIN require CitiPower to provide certain information in relation to the independent verification of its energy consumption forecasts.

As discussed through this section 4.3, CitiPower has engaged NIEIR to prepare its energy consumption forecasts. The independent verification required to be provided to the AER by the RIN is thus provided in the attached NIEIR report. In preparing its forecasts, NIEIR adopted methods, processes and assumptions that it considered reasonable. As noted on its website (http://www.nieir.com.au), NIEIR has built up considerable expertise in the economic analysis of energy issues in Australia.

NIEIR's forecasts have been applied in this Regulatory Proposal.

4.3.6 Incorporation of energy consumption forecasts in the 2011-15 expenditure forecasts

Paragraph 11.5(c) of the RIN requires CitiPower to provide independent verification of how its energy consumption forecasts have been used in determining the capital and operating expenditure forecasts.

CitiPower has used the energy consumption forecasts in applying the control mechanism and setting prices for Standard Control Services. The energy consumption forecasts have not been used directly in preparing either the capital or operating expenditure forecasts. CitiPower has not sought, and therefore does not have within its possession, custody or control, independent verification of the kind sought by paragraph 11.5(c) of the RIN.

4.4 Customer number forecasts for 2011-15

CitiPower's customer number forecasts for the period 2011-15 have been prepared by NIEIR as part of its annual independent study for CitiPower. NIEIR's most recent forecasts are set out in its report entitled *Electricity sales and customer number projections for the CitiPower region to 2019*.

4.4.1 Methodology used to prepare customer number forecasts

Paragraphs 11.1(c) and 11.2(a) of the RIN require CitiPower to describe and explain the methodology it has used to prepare its customer number forecasts. In describing its methodology, CitiPower has addressed paragraphs 11.2(c) to (i) of the RIN which require specific information about the basis on which the customer number forecasts have been prepared.

NIEIR applies a top down approach to developing CitiPower's customer number forecasts. It forecasts the economic outlook for Australia, Victoria and CitiPower's regional area to 2018-19. This is detailed in chapters 2 to 4 of NIEIR's report. The methodology that NIEIR applies, using its energy forecasting model, to prepare its customer number forecasts is detailed in its report. NIEIR states that:

> *'This model effectively takes NIEIR's state forecast of gross state product (by industry) and disaggregates it into 11 statistical sub-divisions across Victoria and 31 Local Government Areas (LGAs) in Melbourne. As indicated in* [Figure 4-1] *the economic forecasts are consistent with NIEIR's national and state economic models.'*

NIEIR uses a regional model, which has been parameterised using NIEIR's existing State electricity forecasting model, to develop its forecasts of customer numbers in CitiPower's distribution area. The model breaks customers into residential, commercial and industrial customer classes.

CitiPower confirms that, for the purposes of:

- paragraph 11.2(c) of the RIN, it is not aware of NIEIR using a particular base year for the purposes of preparing customer number forecasts off the 2011-15 regulatory control period. CitiPower provided NIEIR with historical customer number data for 2000 to March 2009. NIEIR has applied this data in preparing its customer number forecasts for the next regulatory control period;
- paragraph 11.2(d) of the RIN, a probability of exceedance approach is not relevant to preparing customer number forecasts;
- paragraph 11.2(e) of the RIN, NIEIR's model has been used to prepare the customer number forecasts for the next regulatory control period. This is a proprietary model to NIEIR, to which CitiPower does not have access. Nonetheless, CitiPower sets out its understanding of the NIEIR model's key assumptions and inputs in section 4.4.2 below;
- paragraph 11.2(f) of the RIN, NIEIR's model applies a top down, rather than a bottom up, forecasting process;
- paragraph 11.2(g) of the RIN, weather normalisation is not relevant to preparing customer number forecasts;
- paragraph 11.2(h) of the RIN, spot load or load transfer adjustments are not relevant to preparing customer number forecasts; and
- paragraph 11.2(i) of the RIN, CitiPower is not aware of whether or not NIEIR's model incorporates appliance models given that it is a proprietary model and CitiPower only receives outputs from the model. CitiPower understands that NIEIR's model incorporates average customer energy usage assumptions. However, CitiPower is not privy to the specific nature of these assumptions.

4.4.2 Key assumptions and inputs used in preparing customer number forecasts

Paragraph 11.2(b) of the RIN requires CitiPower to detail the key assumptions and inputs used in developing its customer number forecasts.

Chapter 5 of NIEIR's report sets out the key assumptions and inputs used in developing its customer number forecasts. NIEIR's report states that:

> *'Residential customer number forecasts for each distribution region are driven by dwelling stock forecasts.*
>
> *At the State level, dwelling stock forecasts are an output from NIEIR's detailed construction industry models. The model covers residential building, non-residential building and engineering construction. The residential component covers approvals, commencements, completions and the building stock by type of dwelling. Detailed construction forecasts are currently prepared for a number of national companies and State Government departments.*
>
> *In the Victorian regional model, State forecasts of the dwelling stock are disaggregated into Local Government Area forecasts for Melbourne and Statistical Division forecasts for the rest of Victoria. Population growth is the key driver at the regional level.*
>
> *Non-residential customer number projections are a derivative of the historical growth in energy consumption for each class or network tariff, historical customer growth and average usage by class or network tariff.'*

4.4.3 Historical observations

Paragraph 11.3 of the RIN requires CitiPower to explain how its forecasting methodology is consistent with, and has taken into account, historical observations, and how the resulting forecasts are consistent at different levels of aggregation.

As noted above, CitiPower provided NIEIR with historical customer number data by tariff class for the period 2000 to March 2009. NIEIR has applied this data in preparing its customer number forecasts for the next regulatory control period.

On this basis, CitiPower considers that NIEIR's forecasts are consistent with, and take into account, historical observations.

The NIEIR forecasts are not prepared at different levels of aggregation and, thus, CitiPower is unable to comment on the consistency of NIEIR's customer number forecasts at different levels of aggregation.

4.4.4 Independent verification of customer number forecasts

Paragraphs 11.4 and 11.5(a) and (b) of the RIN require CitiPower to provide certain information in relation to the independent verification of its customer number forecasts.

As discussed through this section 4.3, CitiPower has engaged NIEIR to prepare its customer number forecasts. The independent verification required to be provided to the AER by the RIN is thus provided in the attached NIEIR report. In preparing its forecasts, NIEIR adopted methods, processes and assumptions that it considered reasonable. As noted above, NIEIR has built up considerable expertise in the economic analysis of energy issues in Australia.

NIEIR's forecasts have been applied in this Regulatory Proposal.

4.4.5 Incorporation of customer number forecasts in the 2011-15 expenditure forecasts

Paragraph 11.5(c) of the RIN requires CitiPower to provide independent verification of how its customer number forecasts have been used in determining the capital and operating expenditure forecasts.

CitiPower has used the customer number forecasts to prepare its New Customer Connection capital expenditure forecasts. The customer number forecasts have also been used to calculate the scale escalators applying to the operating expenditure forecasts.

CitiPower has not sought, and therefore does not have within its possession, custody or control, independent verification of the kind sought by paragraph 11.5(c) of the RIN.

5. CAPITAL EXPENDITURE

This Chapter provides information in relation to CitiPower's capital expenditure for Standard Control Services in accordance with the requirements of the Rules and the RIN. This Chapter is structured as follows:

- section 5.1 provides a summary of the forecast capital expenditure;
- section 5.2 provides general information that is applicable to all categories of CitiPower's forecast capital expenditure;
- section 5.3 provides an overall description of CitiPower's capital expenditure;
- sections 5.4 to 5.9 provide information that is specific to particular categories of CitiPower's forecast capital expenditure; and
- section 5.10 provides information about CitiPower's historic and estimated capital expenditure for the current regulatory control period.

5.1 Summary

Table 5.1 summarises CitiPower's forecast capital expenditure, by category, for the 2011-15 regulatory control period.

	$'000s (real 2010)					
Expenditure category	2011	2012	2013	2014	2015	Total
Reinforcements	54,840	59,103	75,655	63,497	47,361	300,456
New customer connections	104,055	106,159	93,503	91,347	94,071	489,135
Total demand related	158,895	165,262	169,158	154,844	141,432	789,591
Reliability and quality maintained	56,099	69,357	63,795	69,781	83,030	342,062
Environmental, safety and legal	4,397	3,980	4,051	3,905	4,121	20,454
SCADA and network control	4,575	4,250	4,552	4,700	4,760	22,837
Total non-demand related	65,071	77,587	72,398	78,386	91,911	385,353
Demand and non-demand related	223,966	242,849	241,556	233,230	233,343	1,174,944
Non-Network	12,799	12,376	12,800	17,143	14,295	69,413
Customer contributions	(40,434)	(41,291)	(35,732)	(34,036)	(34,767)	(186,260)
Net capital expenditure	196,331	213,934	218,624	216,337	212,871	1,058,097

Table 5.1: CitiPower's capital expenditure forecasts for the 2011-15 regulatory control period

5.2 General matters applicable to all capital expenditure categories

5.2.1 Key drivers or inputs and key assumptions

Paragraphs 3.1(b)(ii) and 3.1(c)(vii) of the RIN, and clause S6.1.1(4) of the Rules, require CitiPower to provide information about the key drivers or inputs and key assumptions that it has used in preparing its capital expenditure forecasts.

CitiPower's key drivers or inputs and key assumptions for its capital expenditure forecasts are detailed in Table 5.2 together with information that addresses the requirements of paragraphs 3.1(b)(ii) and (c)(vii) of the RIN.

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
Forecasts of spatial peak demand *Assumption:* Spatial peak demand in the 2011-15 regulatory control period will be as forecast in Regulatory Template 6.3. This assumption relates to Reinforcement capital expenditure.	Spatial forecast peak demand levels for the period 2011-15 have been developed internally by CitiPower and cross checked against independent forecasts prepared by NIEIR and AEMO. Refer to Chapter 4 of this Regulatory Proposal.	Used as a key input to develop the Reinforcement capital expenditure forecasts for the 2011-15 regulatory control period. Refer to Chapter 4 of this Regulatory Proposal.	There are numerous interrelated key drivers influencing the quantum of Reinforcement expenditure. It is therefore not possible to discern the discrete quantum impact of the spatial peak demand forecasts on reinforcement capital expenditure. Chapter 4 of this Regulatory Proposal sets out the forecasts of spatial peak demand.	Reinforcement capital expenditure is driven by various factors including forecast spatial peak demand levels and CitiPower's *Network Augmentation Planning Policy and Guidelines.* Section 5.4.8 of this Regulatory Proposal explains the variance in actual and forecast Reinforcement capital expenditure between the 2006-10 and 2011-15 regulatory control periods.	Reinforcements - The sensitivity of this capital expenditure category to this key assumption is medium and therefore the sensitivity of total forecast capital expenditure is low.
CitiPower's internal documents *Assumption:* CitiPower's *Network Augmentation Planning Policy and Guidelines* (Planning Guidelines) and asset management documents will apply in their current form	CitiPower's internal documents and policies are based on there being no change in CitiPower's reliability targets, and those reliability targets continuing to be as set out in section 5.2.9 of this Regulatory Proposal.	The Guidelines are used in preparing the capital works program for Reinforcements capital expenditure. The asset management documents are used in preparing the capital works program for Reliability and Quality Maintained capital	CitiPower has made this key assumption on the basis that it has no current knowledge of any changes to its policies, strategies and procedures that will occur in the next regulatory control period. CitiPower is therefore not able to provide the AER with any quantum in respect of this key	Reinforcement capital expenditure is driven by various factors including forecast spatial peak demand levels and CitiPower's *Network Augmentation Planning Policy and Guidelines.* Reliability and Quality	Reinforcements - The sensitivity of this capital expenditure category to this key assumption is medium. Reliability and Quality Maintained - The sensitivity of this capital expenditure category to this key assumption is medium.

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
throughout the 2011-15 regulatory control period. This assumption relates to Reinforcement and Reliability and Quality Maintained capital expenditure.	At the time of preparing this Regulatory Proposal CitiPower is not aware of any proposed changes to its Planning Guidelines or asset management documents.	expenditure.	assumption.	Maintained capital expenditure is also driven by various factors including CitiPower's asset management documents and condition based risk management (CBRM) and Reliability Centred Maintenance (RCM) methodologies. Sections 5.4.8 and 5.6.6 of this Regulatory Proposal explains the variance in actual and forecast Reinforcement and Reliability and Quality Maintained capital expenditure between the 2006-10 and 2011-15 regulatory control periods.	The sensitivity of total forecast capital expenditure to this assumption is medium.
CitiPower's internal documents are efficient and prudent *Assumption:* In order to satisfy the capex objectives,	CitiPower has developed its Planning Guidelines and asset management documents over time consistent with industry best practice, having regard to the	The assumption regarding CitiPower's Planning Guidelines is used in preparing its capital works program for Reinforcements capital expenditure.	CitiPower is not able to provide the AER with any quantum in respect of this key assumption. Sections 5.4.8 and 5.6.6 of	Reinforcement capital expenditure is driven by various factors including forecast spatial peak demand levels and CitiPower's *Network Augmentation*	Reinforcements - The sensitivity of this capital expenditure category to this key assumption is low. Reliability and Quality

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
an efficient and prudent operator would plan and maintain overall 'energy at risk' on CitiPower's distribution network consistent with CitiPower's *Network Augmentation Planning Policy and Guidelines* (**Planning Guidelines**). It would also manage CitiPower's assets in accordance with CitiPower's asset management documents. This assumption relates to Reinforcement and Reliability and Quality Maintained capital expenditure.	characteristics of its network and the circumstances in which it operates. CitiPower intends applying these documents in the next regulatory control period.	The assumption regarding the asset management documents is used in preparing its capital works program for Reliability and Quality Maintained capital expenditure.	this Regulatory Proposal explain the nature and impact of this assumption on its expenditure forecasts.	*Planning Policy and Guidelines.* Reliability and Quality Maintained capital expenditure is also driven by various factors including CitiPower's asset management documents and condition based risk management (**CBRM**) and Reliability Centred Maintenance (**RCM**) methodologies. Sections 5.4.8 and 5.6.6 of this Regulatory Proposal explain the variance in actual and forecast Reinforcement and Reliability and Quality Maintained capital expenditure between the 2006-10 and 2011-15 regulatory control periods.	Maintained - The sensitivity of this capital expenditure category to this key assumption is low. The sensitivity of total forecast capital expenditure to this assumption is low.
Regulatory change Assumption: The regulatory obligations and	This assumption is based on CitiPower's existing knowledge of current or impending regulatory	This assumption is used in preparing its Reinforcement, Reliability and Quality Maintained and	CitiPower has made this key assumption on the basis that it has no current knowledge of any changes to its regulatory	There is no impact on the 2011-15 forecast capital expenditure compared to the 2006-10 expenditure from	Reinforcement – This sensitivity of this capital expenditure category to this

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
arrangements currently applicable to CitiPower will continue to apply in their current form throughout the 2011-15 regulatory control period (with the exception of those changes that are discussed in section 5.7 of this Regulatory Proposal). This assumption relates to Reinforcement, Reliability and Quality Maintained, and Environmental Safety and Legal capital expenditure.	reviews.	Environmental Safety and Legal capital expenditure for the 2011-15 regulatory control period. Refer to sections 5.4, 5.6, 5.7, and of this Regulatory Proposal.	obligations and arrangements that will occur in the next regulatory control period. CitiPower is therefore not able to provide the AER with any quantum in respect of this key assumption.	this assumption.	key assumption is low Reliability and Quality Maintained – This sensitivity of this capital expenditure category to this key assumption is low Environmental, Safety and Legal - The sensitivity of this capital expenditure category to this key assumption is low The sensitivity of total forecast capital expenditure is also low.
Forecasts of customer numbers *Assumption:* Customer growth over the 2011-15 regulatory control period will be as forecast in Regulatory Template 6.3. This assumption relates to New Customer Connections	The forecast of customer numbers for the period 2011-15 has been prepared by independent modelling experts NIEIR. Refer to Chapter 4 of this Regulatory Proposal.	This assumption is used as a key input to develop the New Customer Connections capital expenditure forecasts for the 2011-15 regulatory control period. Refer to Chapter 4 of this Regulatory Proposal.	There are numerous interrelated key drivers influencing the quantum of New Customer Connections capital expenditure. It is therefore not possible to discern the discrete quantum impact of each of customer number forecasts and the associated key assumption on	Forecast 2011-15 new customer connection expenditure is calculated based on an efficient base, derived from actual expenditure during the 2006-10 regulatory control period. This expenditure is then adjusted by customer growth forecasts as prepared by NIEIR to determine the 2011-	New Customer Connections - The sensitivity of this capital expenditure category to this key assumption is high and therefore the sensitivity of total forecast capital expenditure is medium.

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
capital expenditure.			New Customer Connection capital expenditure. Section 5.5.4 of this Regulatory Proposal sets out the qualitative impact of forecast customer numbers on New Customer Connection capital expenditure.	15 forecast expenditure. Accordingly, the difference between 2006-10 actual, and 2011-15 estimated, new customer connection capital expenditure reflects an adjustment for customer growth forecasts over this period.	
Labour cost escalators *Assumption:* Nominal wage growth for CitiPower in the 2011-15 regulatory control period will be as forecast in the labour cost escalators outlined in Chapter 7 of this Regulatory Proposal. This assumption relates to all categories of capital expenditure.	The forecast of CitiPower's nominal wage growth for the period 2011-15 has been prepared by independent consultants BIS Shrapnel. Refer to Chapter 6 of this Regulatory Proposal.	Each capital expenditure sub-category is segregated into labour, materials and contracts/other costs. Labour escalators have been applied to adjust the labour cost components of the capital expenditure forecasts for the forecast changes in labour costs over the next regulatory control period. Refer to Chapter 7 of this Regulatory Proposal.	Refer Table in Chapter 7 of this Regulatory Proposal.	The impact of adjusting for nominal wage growth is an increase in the labour component of the 2011-15 forecast capital expenditure as determined by the labour cost escalators outlined in Chapter 6 of this Regulatory Proposal.	The sensitivity of each capital expenditure category forecast, as well as total forecast expenditure, to this assumption is low.
Contracts/other cost escalator	The forecast of CitiPower's nominal contracts/other cost growth for the period 2011-15	Each capital expenditure sub-category is segregated into labour, materials and	Refer Table in Chapter 7 of this Regulatory Proposal.	The impact of adjusting for nominal contracts/other cost growth is an increase in the	The sensitivity of each capital expenditure category forecast, as well as total forecast

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
Assumption: Nominal contracts/other cost growth for CitiPower in the 2011-15 regulatory control period will be as forecast in the outsourced services wage escalator detailed in Chapter 7 of the Regulatory Proposal. This assumption relates to all categories of capital expenditure.	has been prepared by independent consultants BIS Shrapnel. Refer to Chapter 6 of this Regulatory Proposal.	contracts/other costs. Contracts/other cost escalators have been applied to adjust the contracts/other cost component of the capital expenditure forecasts for the forecast changes in contracts/other costs over the next regulatory control period. Refer to Chapter 7 of this Regulatory Proposal.		contracts/other costs component of the 2011-15 forecast capital expenditure as determined by the outsourced services wage escalator detailed in Chapter 6 of the Regulatory Proposal.	expenditure, to this assumption is low.
Materials cost escalators *Assumption:* The nominal escalations in the cost of materials over the 2011-15 regulatory control period will be as forecast in the material cost escalators outlined in Chapter 7 of this Regulatory Proposal. This assumption relates to all categories of capital expenditure.	The forecast nominal escalations in the cost of materials for the period 2011-15 have been prepared by independent consultants SKM. Refer to Chapter 6 of this Regulatory Proposal.	Each capital expenditure sub-category is segregated into labour, materials and contracts/other costs. Material escalators have been applied to adjust the materials cost component of the capital expenditure forecasts for the forecast changes in material costs over the next regulatory control period.	Refer Table in Chapter 7 of this Regulatory Proposal.	The impact of adjusting for changes in the cost of materials is an increase in the materials cost component of the 2011-15 forecast capital expenditure as determined by the material cost escalators detailed in Chapter 6 of the Regulatory Proposal.	The sensitivity of each capital expenditure category forecast, as well as total forecast expenditure, to this assumption is low.

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
		Refer to Chapter 7 of this Regulatory Proposal.			
Forecast inflation *Assumption:* Forecast annual inflation over 2011 to 2015 will be equal to the geometric average of annual inflation forecasts over the 10 year period starting from 2011 using RBA annual inflation forecasts where available, and otherwise using the mid point of the RBA inflation target range. This assumption relates to all categories of capital expenditure.	This inflation forecast is based on the AER's preferred approach as set out in the NSW Final Determination.	Forecast annual inflation over 2011 to 2015 is used to convert the nominal escalators to real escalators and to convert 2010 real expenditure and revenue forecasts to nominal expenditure and revenue forecasts.	There are numerous interrelated key drivers influencing the quantum of each capital expenditure category. It is therefore not possible to discern the discrete quantum impact of forecast inflation and the associated key assumption on the forecast expenditure for each capital expenditure category.	Forecast real expenditure will differ from actual 2006-10 real expenditure by the inflation adjusted nominal cost escalators, all else being equal. Forecast nominal expenditure is independent of the inflation forecast.	The sensitivity of each capital expenditure category forecast, as well as total forecast expenditure, to this assumption is low.
Unit rates applied to key items of plant and equipment for both labour and material unit rates *Assumption:* The unit rates currently incurred by CitiPower and reflected in the current average costs of works will be the	CitiPower internally derives its input costs on the basis of the current average costs of undertaking similar projects and capital work programs over the current regulatory control period. These unit rates represent an	This assumption applies to the forecasting of all categories of capital expenditure. Refer to Chapter 7 of this Regulatory Proposal.	There are numerous interrelated key drivers influencing the quantum of each capital expenditure category. It is therefore not possible to discern the discrete quantum impact of unit rates and the associated key assumption on the	There is no impact on the 2011-15 forecast capital expenditure compared to the 2006-10 expenditure resulting from the unit rates key assumption. Unescalated unit rates are simply derived from 2006-10	The sensitivity of each capital expenditure category forecast, as well as total forecast expenditure, to this assumption is high.

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
unescalated unit rates incurred by CitiPower in the 2011-15 regulatory control period. The unescalated unit rates comprise a labour, materials and contract component. Each component is separately adjusted by relevant escalator (labour, materials and contract) as discussed above. This assumption relates to all categories of capital expenditure.	aggregation of materials and other costs such as labour required to complete the works.		forecast expenditure for each capital expenditure category.	expenditure.	
Expenditure on new customer connections *Assumption:* CitiPower's base year gross capital expenditure on new customer connections (2009 total expenditure for projects less than $300,000 and the annual average of 2008-10 inclusive total expenditure for projects greater than or	2009 is an efficient base year for new customer connections of less than $300,000 because it is the most recent information about small customer connections and these are generally negotiated and constructed in a 12 month period. The average expenditure for	This assumption is applied in forecasting capital expenditure on new customer connections for the 2011-15 regulatory control period. Refer to Chapter 5 of this Regulatory Proposal.	Refer to Chapter 5 of this Regulatory Proposal for the quantum of the base year gross capital expenditure on new customer connections. New Customer Connection capital expenditure for the current regulatory control period is set out in Regulatory Template 2.1	There is no impact on the 2011-15 forecast capital expenditure compared to the 2006-10 expenditure resulting from the expenditure on new customer connections key assumption. Efficient base year expenditure, used to prepare the 2011-15 expenditure forecasts is simply derived	New Customer Connections - The sensitivity of this capital expenditure category to this key assumption is high and therefore the sensitivity of total forecast capital expenditure is medium.

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
equal to $300,000) reflects the capital expenditure that would have been incurred by an efficient and prudent operator to satisfy the capital expenditure objectives. This assumption relates to New Customer Connection capital expenditure.	2008-10 is used for new customer connections of more than $300,000, because these projects typically take more than one year to negotiate and construct. All New Customer Connection capital expenditure is externally initiated by customers, rather than internally initiated by CitiPower, and is undertaken in accordance with ESCV's Guideline 14. It is therefore prudent and efficient. Refer to Chapter 5 of this Regulatory Proposal.			from expenditure during the 2006-10 regulatory control period.	
New customer capital contributions In each year of the 2011-15 regulatory control period, the ratio of customer contributions received to new customer connections	Capital contributions are to continue to be calculated in accordance with the ESCV's Guideline 14 in the 2011-15 regulatory control period. Adjustments to the 2009	This assumption is applied in forecasting capital expenditure on new customer connections for the 2011-15 regulatory control period. Refer to Chapter 5 of this	Section 5.5 of this Regulatory Proposal sets out the quantum impact of customer contributions on New Customer Connections capital expenditure.	The 2011-15 forecast new customer capital contributions are lower than those recorded in the fourth year of the 2006-10 regulatory control period.	New Customer Connections - The sensitivity of this capital expenditure category to this key assumption is low and therefore the sensitivity of total forecast capital expenditure is

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
expenditure will be that ratio realised in 2009 after adjusting the customer contributions received in 2009 for the forecast effects of the AER's impending decision on 'fair and reasonable' CitiPower MCR charges. This assumption relates to New Customer Connection capital expenditure.	capital contributions were made on the basis that the AER's impending decision on 'fair and reasonable' CitiPower MCR charges will be substantively similar to the AER's position outlined in its *Formal Decision on CitiPower's current approach to charge new customers capital contribution for upstream network augmentation and further consultation on what should be the fair and reasonable charging rates* of 17 July 2009. This assumption is based on an expectation that it will be prudent for CitiPower to amend its charges as a result of the AER's impending decision on 'fair and reasonable' CitiPower MCR charges (without prejudice).	Regulatory Proposal.		This difference is due to adjustments made to the 2009 capital contributions resulting from the AER's impending decision on 'fair and reasonable' CitiPower MCR charges. On the basis of the AER's impending decision, CitiPower reduced the MCR component of capital contribution by around 40 per cent.	also low.

Key drivers or inputs and key assumptions	Source or basis used to develop the assumption	Whether and how the assumption has been applied / taken into account	Quantum for purposes of paragraph 3.1(b)(ii) of the RIN	Effect / impact of assumption on forecast expenditure	Sensitivity of forecast capital expenditure for purposes of paragraphs 3.1(c)(vii)(3), 3.3(b)(iii)(2), 3.5(b)(iii)(2) and 3.7(b)(iii)(2) of the RIN
	Refer to Chapter 5 of this Regulatory Proposal.				
2010 indexation *Assumption:* 2009 dollars are related to 2010 dollars by CPI. This assumption relates to all categories of capital expenditure. This assumption relates to all categories of capital expenditure.	This CPI assumption is based on that required and specified by the AER's Regulatory Templates. Refer to Chapter 6 of this Regulatory Proposal.	This assumption is applied to escalate nominal $2009 capital expenditure to $2010 capital expenditure forecasts as required by the AER's RIN. Refer to Chapter 6 of this Regulatory Proposal.	The quantum impact of 2010 indexation and the associated key assumption on the forecast expenditure for each capital expenditure category in real dollars in anticipated to be zero..	There is no impact on the 2011-15 forecast capital expenditure compared to the 2006-10 expenditure resulting from the application of this assumption.	The sensitivity of each capital expenditure category forecast, as well as total forecast expenditure, to this assumption is low.

Table 5.2: Key drivers or inputs and key assumptions - capital expenditure

Sections 5.4 to 5.9 of this Regulatory Proposal detail where the key drivers or inputs and key assumptions have been applied in developing the forecasts for each category of capital expenditure.

As required by clause S6.1.1(5) of the Rules, the reasonableness of the key assumptions that underpin CitiPower's capital expenditure forecasts was certified by CitiPower's Board. This certification is provided in Chapter 26 of this Regulatory Proposal.

CitiPower notes that, for the purposes of paragraph 3.1(c)(viii) of the RIN, the following *'key drivers or inputs'* identified by the AER in its 'Definition and Interpretation' to the RIN are not relevant to this Regulatory Proposal and have not been used to prepare forecast capital expenditure for the 2011-15 regulatory control period:

- forecasts of utilisation levels - CitiPower has not used forecasts of network wide utilisation. This is because forecast capital expenditure has been built up by the analysis of loading and utilisation only at those specific network assets where the loading exceeds, or is forecast to exceed, the criteria stated in CitiPower's Network Planning Guidelines;

- forecast of weighted average remaining life of assets - CitiPower's asset management documents highlight that asset condition, not the calculation of the network wide average remaining life, is the key driver in the preparation of capital expenditure forecasts;

- forecasts of energy consumption - CitiPower has used the energy consumption forecasts in applying the control mechanism and setting prices for Standard Control Services. The energy consumption forecasts have not been used directly in preparing either the capital or operating expenditure forecasts; and

- forecasts of line length - CitiPower's line length forecasts are an estimation only, based on the anticipated growth of the network, and have not been used to prepare capital expenditure forecasts.

These matters have therefore not been considered in developing CitiPower's forecast capital expenditure for the next regulatory control period.

5.2.2 Information about material assets

Clause S6.1.1(1) of the Rules requires CitiPower to provide information about the location and cost of its material assets and the categories of distribution services which are provided by these assets.

Figure 5-1 provides a map of CitiPower's material assets.

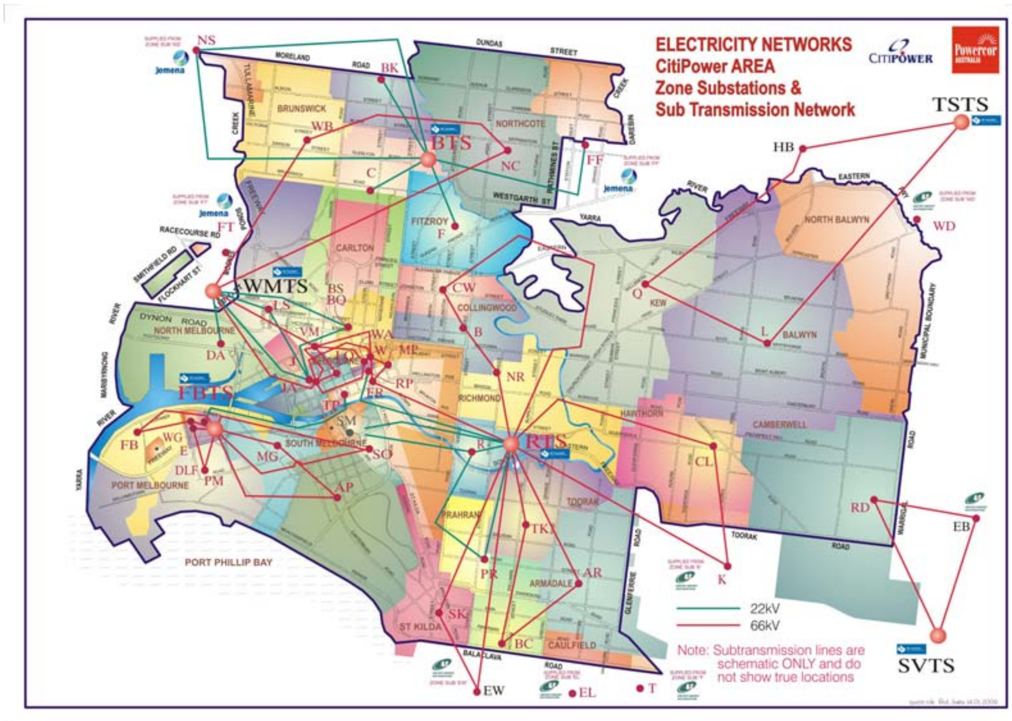

Figure 5-1: Map of CitiPower's material assets

Regulatory Template 2.1 provides details of CitiPower's capital expenditure for the previous, current and next regulatory control period by feeder type, being: CBD and urban.

5.2.3 Regulatory obligations

Paragraph 3.1(b)(iii) of the RIN requires CitiPower to identify the regulatory obligations or requirements that are relevant to its forecast capital expenditure.

CitiPower is subject to a number of service standard, and other regulatory, obligations under the *National Electricity (Victoria) Act 2005* (**NEL**), *Electricity Industry Act 2000* and *Electricity Safety Act 1998*. Various other legislation, such as roads management, occupational health and safety (**OHS**) and the environment, also directly impact on CitiPower's works and activities. New regulatory measures relating to climate change also have the potential to affect CitiPower, such as the Carbon Pollution Reduction Scheme, *Energy Efficiency Opportunities Act 2007*, the Renewable Energy Target and the Victorian Energy Efficiency Target Scheme.

The *Electricity Industry Act 2000* and *Electricity Safety Act 1998* give power to a large amount of subordinate legislation, with which CitiPower must comply. These include the *Electricity Distribution Licence*, *Electricity Distribution Code*, *Electricity Industry Guidelines*, *Electricity Safety (Network Asset) Regulations 1999*, *Electricity Safety (Electric Line Clearance) Regulations 2005* and *Electricity Safety (Bushfire Mitigation) Regulations 2003*.

Sections 5.4 to 5.9 of this Regulatory Proposal identify, where applicable, the relevant regulatory obligations or requirements for each capital expenditure category. To the extent that these sections of the Regulatory Proposal do not identify any relevant regulatory obligations or requirements for a particular capital expenditure category, this is because there are no regulatory obligations or requirements of relevance to that capital expenditure category.

Many of the economic regulatory instruments that apply to CitiPower were previously administered by the ESCV. These include the *Electricity Distribution Licence*, the *Electricity Distribution Code* and the *Electricity Industry Guidelines*. The transition to a national regulatory framework and to the AER has created some uncertainty as to the future of these documents and the basis on which these documents could be amended. For the purposes of this Regulatory Proposal, CitiPower has assumed that, unless otherwise identified, the current arrangements will apply.

5.2.4 Documents taken into account in capital expenditure forecasts

Paragraph 3.2(a) of the RIN requires CitiPower to provide all documents that were taken into account in preparing its capital expenditure forecasts for the next regulatory control period.

These documents are listed in Chapter 30 of this Regulatory Proposal and have been provided separately to the AER with this Regulatory Proposal.

Sections 5.4 to 5.9 of this Regulatory Proposal detail where these documents have been applied in developing the forecasts for each category of capital expenditure.

5.2.5 Policies, strategies and procedures

Paragraphs 3.1(b)(i) and 3.1(c)(iv) of the RIN require CitiPower to provide information in relation to policies, strategies and procedures that it has used in preparing its capital expenditure forecasts. CitiPower has provided these documents to the AER as attachments to this Regulatory Proposal, in accordance with paragraph 1.1(c) of the RIN.

Regulatory Template 6.4 that has been provided with this Regulatory Proposal lists and describes the key internal plans, policies, procedures and strategies that are currently used by CitiPower to plan and conduct its day to day operations. It also describes the nature, reason and impact of any changes in these documents during the current regulatory control period.

Sections 5.4 to 5.9 of this Regulatory Proposal describe how the policies, strategies and procedures have been used or applied in developing the capital expenditure forecasts. CitiPower notes that it engaged Parsons Brinckerhoff (**PB**) to independently review its policies, practices, procedures and governance arrangements. CitiPower has provided PB's report to the AER as an attachment to this Regulatory Proposal.

CitiPower considers that the information provided in Regulatory Template 6.4, and in sections 5.4 to 5.9 of this Regulatory Proposal, fully addresses the requirements of paragraphs 3.1(b)(i) and 3.1(c)(iv) of the RIN.

5.2.6 Consultants' reports

Paragraph 3.1(b)(i) of the RIN requires CitiPower to provide information in relation to the consultants' reports that have been commissioned and relied on in preparing its capital expenditure forecasts. CitiPower has provided these consultants' reports to the AER with this Regulatory Proposal, in accordance with paragraph 1.1(c) of the RIN.

CitiPower has relied on the following consultants' reports in preparing its capital expenditure forecasts for the next regulatory control period:

- BIS Shrapnel in relation to labour cost escalators and contract and other cost escalators;
- SKM in relation to material cost escalators;
- NIEIR in relation to demand and customer connections growth forecasts;
- AECOM in relation to the impacts of climate change;
- PB in relation to CitiPower's policies, practices, procedures and governance arrangements;
- SKM in relation to the management of network fault levels;
- PricewaterhouseCoopers (**PWC**) in relation to whether CitiPower's proposed AMI leveraged projects satisfy the capital expenditure objectives, criteria and factors in clause 6.5.7 of the Rules;
- Gartner Inc in relation to CitiPower's IT Strategic Plan;
- KPMG in relation to the efficiencies of CitiPower's service provision model; and
- Ernst and Young in relation to the commercial benchmark for the margins applied in the provision of corporate services and network services under CitiPower's service provision model.

For the purposes of paragraph 3.1(c)(i) of the RIN, CitiPower confirms that it has not departed from any of the conclusions and recommendations of these consultants' reports in preparing its capital expenditure forecasts.

5.2.7 Planning standards

Paragraphs 3.1(c)(vi), 3.3(a)(ii) and 3.3(b) of the RIN require CitiPower to provide information in relation to how it has incorporated its relevant network planning standards into its capital expenditure forecasts.

CitiPower notes that it does not have externally imposed planning standards of the kind that apply, for example, to the New South Wales DNSPs under their licences.

CitiPower applies a probabilistic approach to network planning in order to satisfy the requirements in the *Victorian Electricity Code* to comply with good asset management practices. This approach is explained in detail in CitiPower's *Distribution System Planning Report 2008*.

A probabilistic approach to network planning involves the relaxing of a deterministic N-1 standard, by estimating the magnitude and duration of potential overloads on the network by analysing various contingency (or *'N-1'*) scenarios. This allows CitiPower to determine, for each potential contingency, the *'energy at risk'*, as well as the number and type of customers that might be affected. Probabilistic planning therefore aims to strike a balance between:

- the cost of providing additional network capacity to remove any constraints; and
- the magnitude of the risk of the load not being supplied as a result of a plant failure.

Implicit in a probabilistic planning approach is the acceptance of the risk that there may be contingency circumstances when the planned capacity will be insufficient to meet actual demand. However, under these conditions, the actual risk may be small when the probability of a forced outage of a particular element of the network is taken into consideration. CitiPower therefore makes a judgment about when to invest and when to manage risk, having regard for the potential costs of low probability events occurring and the availability of contingency plans and other risk mitigation strategies.

CitiPower's planning standards are particularly relevant to the development of its Reinforcement capital expenditure forecasts, which is explained in detail in section 5.3 of this Regulatory Proposal. CitiPower makes its network investment decisions for projects that are aimed at alleviating network constraints by having regard for:

- the relative costs and benefits, including any change in supply reliability, of network augmentation and non-network alternatives to augmentation;
- the uncertainty of assumptions that must necessarily be made in the decision analysis;
- the objective of minimising total life-cycle costs;
- the strong efficiencies that exist with co-ordinated transmission connection and distribution network planning;
- the need to comply with environmental and land-use planning standards, health and safety standards and applicable technical standards; and
- augmentation of the network in a way that takes into account, and minimises, distribution loses.

5.2.8 Proposed reliability targets for STPIS

Paragraph 3.1(c)(v) of the RIN requires CitiPower to explain how the proposed reliability targets for the Service Target Performance Incentive Scheme (**STPIS**) in relation to the System Average Interruption Duration Index (**SAIDI**), the System

Average Interruption Frequency Index (**SAIFI**) and the Momentary Average Interruption Frequency Index (**MAIFI**) have been incorporated into its capital expenditure forecasts.

CitiPower confirms that there is no relationship between the SAIDI, SAIFI and MAIFI targets for the STPIS and its (total, and each category of) forecast capital expenditure for the next regulatory control period.

5.2.9 Deliverability

Paragraph 3.2 of the RIN requires CitiPower to provide information in relation to the proposed deliverability of its capital expenditure forecasts.

CitiPower's major service provider is Powercor Network Services (**PNS**). As discussed in Chapter 22 of this Regulatory Proposal, PNS was established in 2008 in order to provide specialist construction and maintenance services to CitiPower under an arm's length agreement. These services include customer and connection services, asset replacement maintenance services, asset performance (fault) services and network development.

CitiPower has provided to the AER with this Regulatory Proposal a document entitled *CitiPower Ltd's Deliverability Plan 2011–2015*, which explains its proposed deliverability. This document describes the nature and volumes of work that PNS will provide to CitiPower during the next regulatory control period. It also describes how PNS will resource itself in order to do this from internal and external resources.

This document is applicable to all of CitiPower's categories of capital expenditure. No other documents relating to deliverability were expressly taken into account in forecasting capital expenditure.

On this basis, CitiPower confirms that it has contractual arrangements in place to ensure that it can deliver its proposed capital expenditure program in the next regulatory control period. CitiPower also confirms that it has the ability to obtain finance to deliver its proposed expenditure program in the next regulatory control period.

5.2.10 Capital expenditure – compliance

Clause 6.5.7(b)(1)-(3) of the Rules requires CitiPower's capital expenditure forecasts to meet certain compliance requirements. CitiPower confirms that its capital expenditure forecasts for the next regulatory control period:

- comply with the requirements of the RIN, as required by clause 6.5.7(b)(1) of the Rules. CitiPower has provided the AER with a completed version of the Regulatory Templates at the same time as providing this Regulatory Proposal. In addition, Chapter 29 of this Regulatory Proposal provides a table that references each response to a paragraph in Schedule 1 of the RIN and explains where it is provided in, or as part of, this Regulatory Proposal:

- are for expenditure that has been allocated to Standard Control Services in accordance with CitiPower's proposed Cost Allocation Methodology (**CAM**), as is required by clause 6.5.7(b)(2) of the Rules;
- include the total of the forecast capital expenditure for the next regulatory control period, 2011-15, as is required by clause 6.5.7(b)(3)(i) of the Rules; and
- include the forecast capital expenditure for each year of the next regulatory control period, 2011-15, as is required by clause 6.5.7(b)(3)(ii) of the Rules.

5.2.11 Regulatory tests

Clause 6.5.7(b)(4) of the Rules requires CitiPower to identify any forecast capital expenditure that is for an option that has satisfied the regulatory test.

Column E of Regulatory Template 4.2 ('*Material programs*') specifies whether any proposed expenditure is for options that have satisfied the Regulatory Test.

CitiPower considers that the information provided in Regulatory Template 4.2 fully addresses the requirements of clause 6.5.7(b)(4) of the Rules.

5.2.12 Capital expenditure objectives, criteria and factors

Paragraph 3.1(c)(ii) of the RIN requires CitiPower to provide information about whether and how its capital expenditure forecast (in total and by capital expenditure category) relates to the capital expenditure objectives, criteria and factors in clause 6.5.7(a), (c) and (d) of the Rules.

The discussion below demonstrates how CitiPower's total capital expenditure forecast relates to the capital expenditure objectives, criteria and factors. Attachment C0138 sets out how CitiPower's capital expenditure forecast, by sub category of expenditure, relates to the capital expenditure objectives, criteria and factors.

Capital expenditure objectives

CitiPower considers that its forecast capital expenditure will enable it to meet the capital expenditure objectives in clause 6.5.7(a) of the Rules, so that:

- it meets or manages the demand for:
    - network services, measured in terms of maximum demand or energy consumption;
    - connection services, measured in terms of the number of new connections; and
    - unmetered supplies, measured in terms of the number of new type 7 metering installations.

- it complies with regulatory obligations that apply to its network and connection services and relevant unmetered supplies. CitiPower has assumed the current Victorian regulatory arrangements will apply unless otherwise identified; and
- its distribution system, and network and connection services and unmetered supplies, meet relevant quality, reliability, safety and security of supply standards.

CitiPower believes its capital expenditure forecasts will deliver these outcomes in the next regulatory control period because its:

- Reinforcement capital expenditure, as explained in section 5.3, will enable it to augment its distribution network in order to ensure that it has sufficient capacity to avoid:
    - asset utilisation rates exceeding the upper bounds of good engineering practice, in order to ensure the safety, reliability and security of supply of the distribution network; and
    - the need to increase the repair and maintenance of heavily loaded assets.
- New Customer Connection capital expenditure and Customer Contributions, as explained in section 5.5, will enable it to meet customers' demand for new and upgraded connection services. These forecasts are influenced by economic conditions and development demographics, including major projects arising from mining, pipelines, generation and agricultural development;
- Reliability and Quality Maintained capital expenditure, as explained in section 5.6, will enable it to maintain its network performance within acceptable risk levels, as well as to replace assets that have failed. Reliability and Quality Maintained capital expenditure is necessary because, with time, network assets age and deteriorate and, if they are not replaced, they may fail or may operate at a sub-standard level. This may result in a reduced level of service reliability and quality;
- Environmental, Safety and Legal capital expenditure, as explained in section 5.7, will enable it to be compliant with applicable environmental, electrical safety regulatory and other Victorian and national legislative obligations, in particular the requirements of Energy Safe Victoria, the Victorian Environmental Protection Authority and Parks Victoria;
- Supervisory Control and Data Acquisition (**SCADA**) and Network Control, as explained in section 5.8, will enable it to provide 24 hour monitoring and control of its zone and sub-transmission substation assets and other distribution network assets (including feeders). This capital expenditure will strengthen network performance, improve data security, increase data visibility and provide more accurate and timely information to customers on fault rectification; and
- Non-System capital expenditure, as explained in section 5.9, will enable it to invest in information technology, general equipment, motor vehicles, office

furniture and property that, while not directly related to the distribution system, are essential to ensuring that CitiPower's distribution system, and its distribution services, meet relevant quality, reliability, safety and security of supply standards.

Importantly, for the reasons described in section 5.2.9 of this Regulatory Proposal, CitiPower believes that it can physically deliver its capital expenditure program in the next regulatory control period, in order to achieve the capital expenditure objectives.

Capital expenditure criteria

CitiPower considers that its forecast capital expenditure (in total and by capital expenditure category) is consistent with and promote the capital expenditure criteria in clause 6.5.7(c) of the Rules, as it reflects:

- the efficient costs of achieving the capital expenditure objectives;
- the costs that a prudent operator in CitiPower's circumstances would require to achieve the capital expenditure objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

CitiPower believes its capital expenditure reflects these criteria because it has developed its forecasts by applying a prudent approach to developing its expenditure forecasts. This approach includes:

- having regard for its historic expenditure levels. Sections 5.4.8, 5.5.5, 5.6.6, 5.7.6, 5.8.7 and 5.9.7 of this Regulatory Proposal explain the variances between CitiPower's actual and forecast capital expenditure, by expenditure category, in the current and next regulatory control periods;
- using, where relevant, forecasts of maximum demand, energy consumption and customer numbers, as discussed in Chapter 4 of this Regulatory Proposal;
- considering applicable regulatory requirements, as discussed in section 5.2.3 of this Regulatory Proposal;
- applying the internal plans, policies, procedures and strategies that are listed and explained in Regulatory Template 6.4, and are discussed for each expenditure category in sections 5.4 to 5.9 of this Regulatory Proposal;
- applying the same reliability targets in the next regulatory control period as it has in the current regulatory control period;
- applying the planning standards in the next regulatory control period that are explained in section 5.2.7 of this Regulatory Proposal;

- drawing on relevant consultants' reports, which are listed in section 5.2.6 of this Regulatory Proposal. The application of these reports is discussed in sections 5.4 to 5.9 of this Regulatory Proposal;
- applying the efficient unit costs and expenditure escalations discussed in Chapter 7 of this Regulatory Proposal;
- undertaking regulatory tests, where relevant. Column E of Regulatory Template 4.2 (material projects) specifies whether any proposed expenditure is for options that have satisfied the Regulatory Test; and
- having regard, where relevant, to non-network alternatives, as discussed in Chapter 8 of this Regulatory Proposal.

In considering the circumstances in which it operates, CitiPower considers that it is particularly important to recognise that CitiPower's network is the most concentrated of the five Victorian electricity distribution networks. Its area accounts for 25 per cent of Victoria's employment and 22 per cent of its Gross State Product (**GSP**). It is also home to virtually all of the major offices of government and the private sector. It is also home to world-class cultural and sporting facilities such as Federation Square, the Melbourne Cricket Ground, the Victorian Arts Centre and the home of the Australian Tennis Open, Melbourne Park. The composition of CitiPower customers, with the emphasis on business and important social infrastructure, places a particular importance on the security of electricity supply.

Capital expenditure factors

The capital expenditure factors in clause 6.5.7(e) of the Rules are the matters that the AER must have regard to in assessing whether CitiPower's capital expenditure forecasts reasonably reflect the capital expenditure criteria in clause 6.5.7(c) of the Rules. As discussed above, CitiPower considers that its capital expenditure forecasts in this Regulatory Proposal (in total and by capital expenditure category) fully reflect the capital expenditure criteria.

The capital expenditure factors in clauses 6.5.7(e)(1) and (3) of the Rules require the AER, in assessing the capital expenditure forecasts against the capital expenditure criteria, to have regard for information included in or accompanying the Building Block Proposal and to have regard to the AER's own analysis. CitiPower has set out in this Regulatory Proposal its Building Block Proposal and its submissions in respect of the material published by the AER to date where relevant and thus has addressed these capital expenditure factors.

CitiPower is not yet capable of addressing the capital expenditure factor in clause 6.5.7(e)(2) of the Rules because no submissions in respect of its Building Block Proposal have yet been received by the AER.

The capital expenditure factors in clauses 6.5.7(e)(4) to (5) of the Rules require the AER, in assessing the capital expenditure forecasts against the capital expenditure criteria, to have regard for capital expenditure benchmarks. CitiPower has not addressed this capital expenditure factor in its Regulatory Proposal.

The capital expenditure factor in clause 6.5.7(e)(5) of the Rules requires the AER, in assessing the capital expenditure forecasts against the capital expenditure criteria, to have regard for CitiPower's actual and estimated capital expenditure in the current and previous regulatory control periods.

CitiPower has addressed this capital expenditure factor as follows.

Regulatory Template 3.1 provides a detailed breakdown of its capital expenditure in the previous and current regulatory control periods. In addition:

- section 5.10 of this Regulatory Proposal provides details of CitiPower's actual and estimated capital expenditure in the current regulatory control period.
- sections 5.4.8, 5.5.5, 5.6.6, 5.7.6, 5.8.7 and 5.9.7 of this Regulatory Proposal explain the variances between actual and forecast capital expenditure, by expenditure category, in the current and next regulatory control periods.

The capital expenditure factor in clause 6.5.7(e)(6) of the Rules requires the AER, in assessing the capital expenditure forecasts against the capital expenditure criteria, to have regard for whether the relative prices of operating and capital inputs. CitiPower has not addressed this capital expenditure factor in this Regulatory Proposal. This is because CitiPower has forecast operating expenditure based on 2009 base year expenditure.

CitiPower notes for completeness that the unit costs which underpin the capital expenditure forecasts have been developed on the basis of the current average costs of undertaking similar capital works in the current regulatory control period. Costs of program related capital works are recorded against specific function codes and are divided by the quantity of physical units of work undertaken.

As a consequence, these unit costs represent an aggregation of materials and other costs, such as labour, that are required to complete the works. These rates do not include overheads or escalators that are separately applied.

Section 6.14.1 of this Regulatory Proposal also provides information about the nature, and basis for, the labour, material, contractor and other cost escalators that have been applied in preparing the capital expenditure forecasts. CitiPower engaged expert consultants to forecast the real growth in the costs of each of these sub categories. The escalators determined by the expert consultants were directly applied in the development of the capital expenditure forecasts.

The capital expenditure factors in clause 6.5.7(e)(7) of the Rules require the AER to consider the substitution possibilities between capital and operating expenditure. This supports the requirement in clause S6.1.3(1) of the Rules for CitiPower to identify and explain any significant interactions between its forecast capital and operating expenditure.

There are three key aspects of CitiPower's capital and operating expenditure forecasts that present substitution possibilities, being:

- aging assets;
- investment in new systems, processes, plant and equipment; and
- purchasing or leasing new equipment or facilities.

As assets age, their condition deteriorates and maintenance costs increase, as does their risk of failure. Furthermore, the failure of aged assets presents their own risks[8]. CitiPower must evaluate whether it is more prudent and efficient to replace these assets, thereby incurring capital expenditure, or whether additional operating expenditure should be incurred to manage the risk associated with the assets.

CitiPower has undertaken an assessment of the age and condition of its electricity distribution network assets. On the basis of this assessment, CitiPower has developed capital and operating expenditure forecasts that represent the optimal mix of capital asset replacement, and enhanced condition monitoring, by which to balance costs and risks.

As its commercial and operational requirements evolve, and newer technologies become available, CitiPower must evaluate whether it is prudent and efficient to invest capital expenditure in new systems, processes, plant and equipment, thereby reducing operating expenditure.

CitiPower has adopted the general principle that capital expenditure proposed for the primary purpose of delivering productivity improvements and reductions in operating expenditure should not be included in its capital expenditure proposal.

As requirements arise that necessitate the purchase or lease of new equipment, CitiPower must evaluate whether it is prudent and efficient to make a capital investment in the purchase of new equipment, or whether the option of leasing the new equipment (and thereby incurring higher operating expenditure) is more prudent and efficient.

CitiPower's financial management processes require a financial evaluation (based on discounted cash flow analysis) to be performed whenever expenditure is proposed relating to the provision of Standard Control Services, and there are competing options available with respect to financing. As a result of these analyses, CitiPower has determined to purchase the vast majority of its vehicles, heavy equipment, property, and IT assets. The exceptions where CitiPower has elected to lease equipment typically relate to short-term requirements, or where suitable purchase options are unavailable.

CitiPower's plans, policies, procedures and strategies have regard for the interactions, and substitution possibilities, between its capital and operating expenditure programs and they are inherent in the efficient base year costs. Examples of these interactions and substitution possibilities include:

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[8] Typically, older assets are more difficult to repair after failure owing to their technical obsolescence and therefore lack of availability of spare parts and/or relevant expertise and the associated (un)willingness of vendors to continue to provide support.

- the asset inspection program in the reliability and quality maintained capital expenditure forecast identifies whether defective assets need to be replaced by undertaking capital expenditure or alternatively whether they require condition based maintenance. Furthermore, replacing defective assets reduces the need for future maintenance as new assets are less likely to fail in service;

- reinforcement capital expenditure results in the augmentation of the distribution system and requires the newly installed assets to be operated and maintained in accordance with CitiPower's asset management policies. If inadequate augmentation work is undertaken then existing assets are more likely to fail as demand grows, which may increase the need for emergency maintenance expenditure; and

- non-network capital expenditure, such as on IT, motor vehicles, property and general equipment, are necessary enablers of the operating expenditure program and are needed to support the safe and efficient delivery of distribution services. Once they are purchased, motor vehicles and property require ongoing operating and maintenance costs.

The capital expenditure factor in clause 6.5.7(e)(8) of the Rules requires the AER, in assessing the capital expenditure forecasts against the capital expenditure criteria, to have regard to whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable STPIS. It is not clear to CitiPower what clause 6.5.7(e)(8) of the Rules is intended to address. This is because labour costs are only one element of CitiPower's capital and operating expenditure forecasts and CitiPower does not understand how it could demonstrate that these costs are consistent with the incentives under the STPIS. CitiPower has therefore not provided information to the AER to address this factor.

Clause 6.5.7(e)(9) of the Rules requires the AER, in assessing the capital expenditure forecasts against the capital expenditure criteria, to have regard for the extent the capital expenditure forecast is referrable to arrangements with other parties that do not reflect arm's length terms.

As discussed in Chapter 22 of this Regulatory Proposal, CitiPower outsources a number of its functions including, its:

- field services work – these are provided to CitiPower by PNS under a Network Services Agreement; and

- back-office services, which includes its corporate services, customer services, and IT support services – these are provided to CitiPower by CHED Services under a Corporate Services Agreement.

CitiPower engaged Ernst and Young to establish the commercial benchmark for the margins applied in the Network Services Agreement and the Corporate Services Agreement.

CitiPower also engaged KPMG to quantify the efficiencies that are captured by CitiPower's service provision model relative to it providing these services in-house. KPMG, where possible, used publicly available sources of benchmarking information when estimating the efficient costs of the stand alone DNSP. KPMG found that if CitiPower had delivered its nominated services for the year ended 31 December 2008 on a standalone basis, its efficient cost of service delivery would have been $19.049 million (45 per cent)($2008) more than the costs exclusive of margins it actually incurred for these services. In particular, in house:

- corporate and customer services would have cost $11.968 million ($2008) more than it actually incurred;
- asset management services would have cost $3.794 million ($2008) more than it actually incurred; and
- network services would have costs $3.287 million ($2008) more than it actually incurred.

The efficiency of CitiPower's service provision model is borne out in the actual efficient capital and operating expenditure performance of CitiPower over the 2006-10 regulatory control period.

Clause 6.5.7(e)(10) of the Rules requires the AER, in assessing the capital expenditure forecasts against the capital expenditure criteria, to have regard for the extent CitiPower has made provision for efficient non-network alternatives.

CitiPower has not made an explicit provision in its capital expenditure forecasts for non-network alternatives, although it has had regard for non-network alternatives in the development of its capital expenditure forecasts. CitiPower will continue to examine the relative merits of network, and non-network, alternatives in making its future expenditure decisions. Non-network alternatives will be pursued where they provide the best solution in the circumstances to address the identified need.

5.2.13 Matters that are not relevant

Paragraph 3.1(c)(viii) of the RIN requires CitiPower to identify why any matters referred to in paragraph 3.1 of the RIN are not relevant to its capital expenditure forecast (in total and by category), and to explain why this is the case.

This Chapter 5 of the Regulatory Proposal addresses all of the relevant matters in paragraph 3.1 of the RIN. However, CitiPower:

- does not have any Load Movement capital expenditure. It has therefore not addressed the matters detailed in paragraph 3.4 of the RIN or any other paragraph of the RIN which requires information about Load Movement capital expenditure;
- does not have any Reliability and Quality Improved capital expenditure. It has therefore not addressed the matters detailed in paragraph 3.6 of the RIN or any

other paragraph of the RIN which requires information about Reliability and Quality Improved capital expenditure; and

- notes that, as discussed in section 5.2.1 above, not all of the categories of key drivers or inputs and key assumptions that are identified in the RIN are relevant to the capital expenditure forecasts. CitiPower's capital expenditure key drivers or inputs and key assumptions are detailed in section 5.2.1 of this Regulatory Proposal.

CitiPower has identified in this Chapter 5 of the Regulatory Proposal all matters relevant to forecast capital expenditure (in total and by capital expenditure category).

5.3 Overall description of capital expenditure

Paragraph 3.1(a) of the RIN requires CitiPower to provide an overall description of its forecast capital expenditure, including to describe its aims and objectives and how the different categories of expenditure are distinguished.

CitiPower's aims and objectives for its forecast capital expenditure are the capital expenditure objectives set out in clause 6.5.7(a) of the Rules. Section 5.2.12 of this Regulatory Proposal explains how CitiPower considers that it will meet these objectives.

CitiPower's forecast capital expenditure for the 2011-15 regulatory control period is the total of the forecast capital expenditure categories being: Reinforcements; New Customer Connections; Reliability and Quality Maintained; Environmental, Safety and Legal; SCADA and Network Control; and Non-Network.

Sections 5.4 to 5.9 of this Regulatory Proposal include a description of the nature, aims, objectives and distinguishing features, and sets out the methodology for forecasting expenditure, for each of the capital expenditure categories.

5.4 Reinforcement capital expenditure

5.4.1 Expenditure forecast for 2011-15

Clause S6.1.1(1) of the Rules requires CitiPower to provide a forecast of its Reinforcement capital expenditure for the next regulatory control period. This forecast is detailed in Table 5.3.

	$'000s (real 2010)					
Expenditure category	2011	2012	2013	2014	2015	Total
Reinforcements	54,840	59,103	75,655	63,497	47,361	300,456

Table 5.3: CitiPower's reinforcement capital expenditure forecasts for 2011-15

5.4.2 Relevant key drivers or inputs and key assumptions

Paragraphs 3.3(a)(i) and 3.3(b) of the RIN require CitiPower to provide information in relation to the key drivers or inputs and key assumptions that are relevant to the Reinforcement capital expenditure forecast.

The key drivers or inputs and key assumptions that are relevant to the Reinforcement capital expenditure forecast are:

- forecast of spatial peak demand;
- CitiPower's internal documents;
- CitiPower's internal documents are efficient and prudent;
- regulatory change;
- labour cost escalators;
- contracts/other cost escalators;
- material cost escalators;
- forecast inflation;

- unit rates; and
- 2010 indexation.

Section 5.2.1 of this Regulatory Proposal provides the information required by paragraph 3.3(b) of the RIN for each of these key drivers or inputs and key assumptions.

CitiPower observes, for the purposes of paragraph 3.3(a)(iii) of the RIN, that there are no considerations relevant to the Reinforcement capital expenditure forecast other than those relevant key drivers or inputs identified above.

For the purposes of paragraph 3.3(c) of the RIN, CitiPower notes that the forecast of customer numbers, expenditure on new customer connections and new customer capital contributions are not relevant to forecast Reinforcement capital expenditure. Reinforcement capital expenditure forecasts are not dependent on customer numbers, but rather the remaining capacity available on the network ie maximum demand. As such customer numbers are not relevant to forecast Reinforcement capital expenditure. Expenditure on customer connections and new customer capital contribution relate to customer initiated works on the network. The Reinforcements capital expenditure category does not include customer initiated works. Therefore expenditure on new customer connections and new customer capital contributions is not relevant to forecast Reinforcement capital expenditure.

5.4.3 Regulatory obligations

Paragraph 3.1(b)(iii) of the RIN requires CitiPower to identify each regulatory obligation or requirement relevant to its Reinforcement capital expenditure.

CitiPower confirms that the only regulatory obligation or requirement of relevance to its Reinforcement capital expenditure is the *Victorian Electricity Distribution Code*.

5.4.4 Nature, aims, objectives and distinguishing features

Paragraphs 3.1(a)(i)-(ii) of the RIN require CitiPower to describe the nature of, and aims and objectives for, its Reinforcement capital expenditure as well as the factors that distinguish it from other categories of capital expenditure.

Reinforcement capital expenditure relates to capital works that are required to augment, based on CitiPower's load forecasts, its:

- sub-transmission network – these are the assets directly connecting to transmission connection points, including 66kV and 22kV sub-transmission lines and zone substations; and
- high voltage and low voltage network – these are the distribution assets below the zone substations including high voltage lines, distribution substations and low voltage lines.

Distribution assets operate at higher utilisation levels as their levels of loading increase. This can affect their long term serviceability. Reinforcement capital expenditure enables CitiPower to augment its distribution network in order to ensure that it has sufficient capacity to avoid:

- asset utilisation rates exceeding the upper bounds of good engineering practice, in order to ensure the safety, reliability and security of supply of the distribution network; and
- the need to increase the repair and maintenance of heavily loaded assets through increased maintenance expenditure.

In this way, CitiPower's Reinforcement capital expenditure forecasts represent what it considers is necessary, for the purposes of clause 6.5.7(a) of the Rules, in order to:

- meet and manage the expected demand for network services over the 2011-15 regulatory control period; and
- ensure that its distribution system, and its network services, meet relevant quality, reliability, safety and security of supply standards.

For the purposes of paragraph 3.1(a)(ii) of the RIN, CitiPower notes that the main distinguishing factors between Reliability and Quality Maintained capital expenditure and Reinforcement capital expenditure are that Reinforcement capital expenditure relates to the capital works that are required to augment CitiPower's sub-transmission and high and low voltage networks, while Reliability and Quality Maintained capital expenditure relates to works that are necessary in light of particular assets' age and/or level of deterioration. CitiPower does not consider that there is any reasonable scope for ambiguity between Reinforcement capital expenditure and any other expenditure category.

5.4.5 Methodology and supporting documentation

Paragraph 3.1(c)(iii) of the RIN, and clause S6.1.1(2) of the Rules, require CitiPower to explain the methodology by which it has prepared its Reinforcement capital expenditure forecasts. In addition, paragraphs 3.2, 3.1(c)(iv), 3.3(a)(ii) and 3.3(b)(i)-(ii) require CitiPower to provide information about documents that it has used in preparing its forecasts.

Reinforcement capital expenditure at the:

- sub-transmission level is driven by the need to manage *'energy at risk'* at each sub-transmission line and each zone substation; and
- high voltage and low voltage level is driven by the need to manage capacity at each feeder.

CitiPower has taken into account the following documents in preparing its Reinforcement capital expenditure forecasts:

- the *Electricity Networks Network Augmentation Planning Policies and Guidelines*; and

- *Distribution System Planning Report* (**DSPR**); and
- technical standards on equipment including overhead lines, cables and transformers.

These documents are used by CitiPower to determine the need for, and timing of, network reinforcement to address *'energy at risk'* based on the peak demand forecasts at different elements of the network.

CitiPower observes, for the purposes of paragraph 3.1(b)(iii) of the RIN, that the above documents reflect CitiPower's obligations under the *Victorian Electricity Distribution Code* relevant to forecasting Reinforcement capital expenditure.

Maximum demand forecasts

As discussed in Chapter 4 of this Regulatory Proposal, CitiPower prepares its maximum demand forecasts based on a rolling ten year load forecast for each terminal station and zone substation, and a rolling five year load forecast for its sub transmission lines.

CitiPower prepares its ten year maximum demand forecasts by:

- adjusting the most recent actual summer and winter maximum load data, at the zone substation level, to obtain the PoE 50 maximum loads;
- scaling the zone substation PoE 50 maximum loads according to the historic *'underlying'* summer and winter load growth for each zone substation area;
- adjusting for known block customer changes and load transfers; and
- aggregating the zone substation maximum demand forecasts up to each respective terminal station, taking into account of diversity and power factor.

CitiPower prepares its five year N-1 maximum demand forecast for sub-transmission lines by:

- modelling the sub-transmission network, incorporating the relevant zone substation maximum demand forecasts into the model; and
- performing load flow analysis, under different scenarios N-1 scenarios to generate a maximum load forecast for each sub-transmission line.

CitiPower's approach to forecasting peak demand is consistent with the industry standard spatial demand forecasting methodology, whereby the trend between recently measured peak demands is extrapolated linearly to forecast future demand taking into account specific spot load impacts[9].

[9] Spatial demand forecasting has been adopted because demand in a particular region, and therefore the capacity requirements of infrastructure in that region, need not necessarily correlate to overall demand growth.

CitiPower cross checks its internally developed 'bottom up' demand forecasts against forecasts that are independently prepared by NIEIR and AEMO at the terminal station level.

Figure 5-2 shows CitiPower's historic and forecast peak demand for the next regulatory control period. This graph is based on the sum of non-coincident zone substation peak demands.

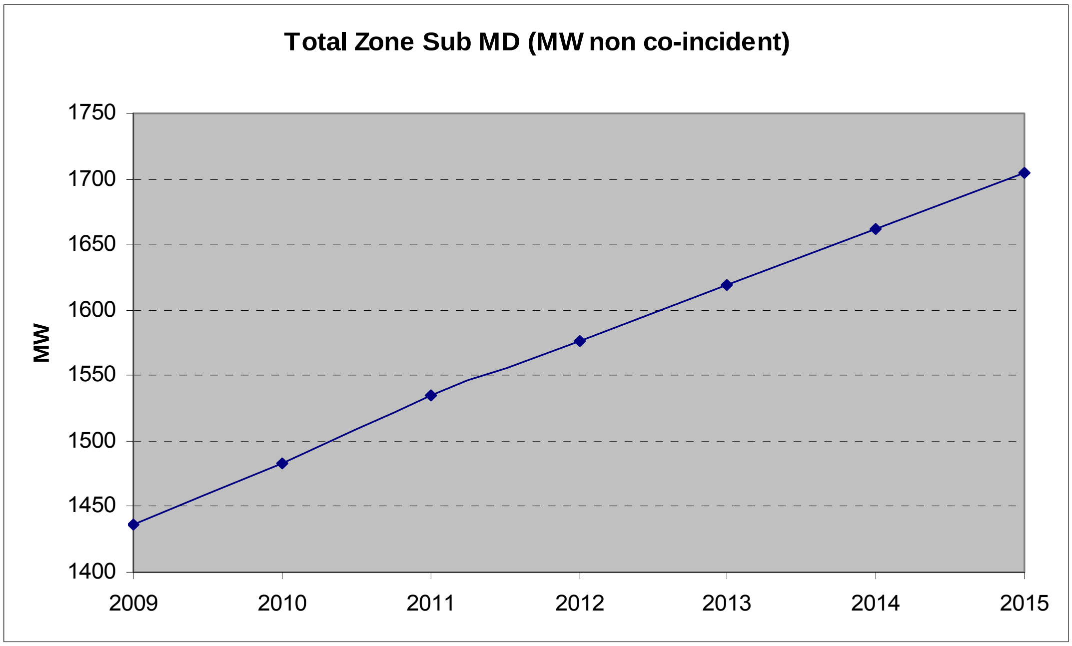

Figure 5-2: CitiPower's historic and projected peak demand forecast

Energy at risk

As noted, the *'energy at risk'*, and therefore the need for network Reinforcement capital expenditure, is determined by:

- CitiPower's planning documentation; and
- the peak demand forecasts.

'Energy at risk' is an estimate of the amount of energy that would not be supplied if a transformer, or a sub-transmission line, was out of service during a critical loading period.

CitiPower's *Network Augmentation Planning Policy and Guidelines* set out the planning criteria for network augmentations. These criteria have recently been reviewed and provide specific requirements in relation to the acceptable level of *'energy at risk'*, consistent with good industry practice. As directed by CitiPower's Capital Investment Committee (**CIC**), these Guidelines require CitiPower to reduce the total levels of *'energy at risk'* associated with zone substation and sub-transmission lines utilisation, to around forecast 2010 levels and to maintain them at these levels over the next regulatory control period[10].

CitiPower identifies a range of options, including non-network solutions where they are feasible and economically efficient, in order to maintain *'energy at risk'* or capacity for the relevant assets at or below 2010 levels. These options are then costed based on the average current costs of undertaking similar projects.

For those investments in distribution assets that are forecast to cost less than $10 million, the least cost option consistent with the relevant geographical network development plan is nominated as the preferred solution. For those investments in distribution assets that are forecast to cost more than $10 million, the preferred solution is currently identified through the Regulatory Test[11] although this threshold is expected to be reduced to $5 million in the next regulatory control period. These *'nominated'* projects are rolled into a master list, which forms the basis of a five and ten year capital works program. The capital works program addressing the current network constraints is reflected into the most recently published DSPR. Both the five and ten year capital works programs are updated on an annual basis at the time of the annual load forecasts are revised.

CitiPower has prepared a report that describes and supports more fully its energy at risk strategy, data and planning criteria. Importantly the Business considers that the recommendations of this report represent best electricity industry practice. A copy of this report, entitled '*Energy at risk and growth related capex*' has been provided as an attachment to this Regulatory Proposal.

Determining the forecast

CitiPower's forecast Reinforcement capital expenditure for the next regulatory control period includes:

- high voltage and low voltage works including augmenting feeders, installing new feeders and upgrading high voltage lines. This is largely a continuation of the volume and level of works undertaken in the current regulatory control period; and

- substation related work including increasing the capacity of existing substations and constructing new substations. This is the largest component of the reinforcement expenditure forecast for the 2011-2015 regulatory control period. This increased program of works is a direct result of changes to *the Network Augmentation Planning Policy and Guidelines*, which require CitiPower to maintain lines' energy at risk at around the forecast 2010 levels.

[10] CitiPower – Capital Investment Committee (CIC) meeting minutes Monday 11 May 2009

[11] CitiPower notes that, in accordance with clause 5.6.2(f) and (g) of the Rules, it undertakes Regulatory Tests for 'large' distribution network assets, which are defined as requiring expenditure in excess of $10 million. In accordance with the Rules' requirements, CitiPower consults on these Regulatory Tests. The results of the Regulatory Tests determine the nominated solutions.

Figure 5-3 shows zone substation energy at risk. This figure illustrates the two scenarios being:

- *'do nothing'* – this is where no capacity augmentation is performed; and
- *'augment'* – this is where capacity augmentation is implemented as reflected in the expenditure forecast.

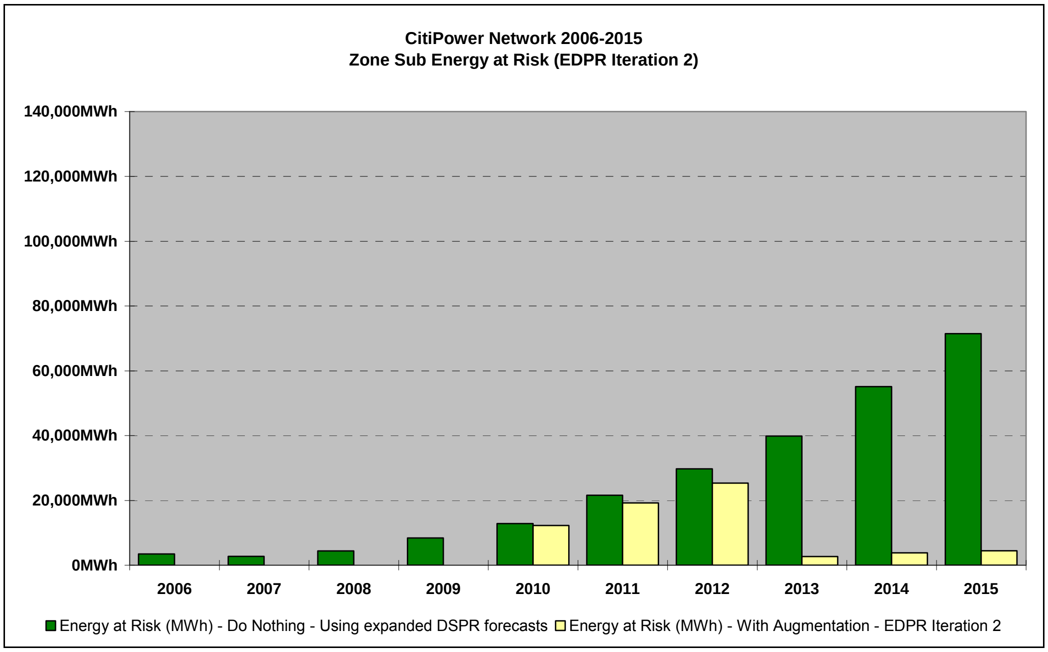

Figure 5-3: Historic and forecast zone substation energy at risk

Specific major reinforcement projects identified for the 2011-15 regulatory control period include:

- continued work on the Metro 2012 project – this project involves upgrading the terminal station at Brunswick to a new 66kV connection point, in order to relieve constraints at the terminal stations that supply the Melbourne CBD, namely West Melbourne Terminal Stations (WMTS 66kV and WMTS 22kV) (these terminal stations supply the northern and western inner central business district and surrounding areas) and the heavily loaded Richmond Terminal Station.

  This project, in conjunction with the CBD Security of Supply project, will address the capacity restrictions and enhance the security of supply to the Melbourne CBD. Forecast expenditure associated with the Metro 2012 project satisfied the Regulatory Test assessment.

- continued work on the CBD Security of Supply project – this project is designed to enhance the security of the electricity supply to the Melbourne central business district (Melbourne CBD) and thereby deliver a higher level of security to Melbourne CBD customers. Again this project was subject to, and satisfied, a Regulatory Test. The ESCV decided in its Final Decision of February 2008 CBD

Security of Supply to amend the Victorian Electricity Distribution Code to require CitiPower to deliver improved network security levels and grant CitiPower access to the pass-through provision in the 2006 Electricity Distribution Price Review to recover the costs of the project. Section 5.7.5 of this Regulatory Proposal details further information, required by the RIN, on the CBD Security of Supply project.

- new projects that will commence in the 2011-2015 regulatory control period including:
  - upgrading the capacity at the Dock Area zone substation;
  - installing a third transformer at the South Bank Zone Substation;
  - installing a third transformer at Balaclava Zone Substation; and
  - upgrading the sub-transmission loop that supplies the Collingwood and North Richmond Zone Substations fed from the Richmond Terminal Station at 66kV.

CitiPower has included a list of material major capital projects and programs in the completed Regulatory Template 4.2 and in Chapter 28.

5.4.6 Other information

Paragraph 13.1 of the RIN requires CitiPower to provide certain information in relation to the utilisation forecast in Table 3C of Regulatory Template 6.1.

CitiPower has provided the following utilisation information in Table 3C of Regulatory Template 6.1:

- historic utilisation information for 2001-08 for subtransmission feeders based on zone substation maximum demands and high voltage feeders. CitiPower records and maintains this information each year; and
- forecast utilisation information for 2009-15 for:
  - subtransmission and high voltage feeders. This information is forecast as part of CitiPower's normal planning processes; and
  - low voltage feeders, which has been based on top-down estimates from distribution substation maximum demands.

CitiPower notes that it does not rely on average utilisation in any way to forecast its capital expenditure. CitiPower has used an internally developed Excel spreadsheet model to calculate utilisation information set out in Table 3C of Regulatory Template 3C. This Excel based model, including calculations contained within the spreadsheets, is provided at Attachment C0184 to this Regulatory Proposal.

5.4.7 Why the forecast expenditure is justified

The majority of the CitiPower Reinforcement expenditure relates to two large projects, being the Metro 2012 capacity upgrade, and the CBD Security of Supply upgrade project. Both these projects require the establishment of new 220/66kV transformation at the Brunswick Terminal Station.

Both these projects have been subject to the Regulatory Tests, in accordance with the Rules requirements, and provide positive benefits in terms of the cost of potential unserved energy. In the case of the CBD Security of Supply project, the ESCV has now mandated this project through an amendment to the Victorian Electricity Distribution Code.

There is a particular need for CitiPower to increase its Reinforcement capital expenditure in the next regulatory control period in order to:

- accommodate capacity growth after a period of increasing network utilisation;
- address new cost pressures, and in particular, those associated with peak demand growth; and
- ensure the delivery of the positive customer benefits identified through the Regulatory Tests assessments published by CitiPower.

5.4.8 Variance between actual and forecast capital expenditure

Clause S6.1.1(7) of the Rules requires CitiPower to explain significant variations in forecast capital expenditure from historical capital expenditure. Paragraph 3.3(b)(iii) of the RIN requires CitiPower to provide information in relation to the matters that have caused a difference between Reinforcement capital expenditure in the current regulatory control period compared with what is forecast for the next regulatory control period.

CitiPower estimates that its Reinforcement capital expenditure for the 2006-10 regulatory control period will be $75 million ($2010). It is forecasting that this will increase to $300 million ($2010) in the 2011-15 regulatory control period, which is an increase of approximately 300 per cent.

The main factors driving this increase in Reinforcement capital expenditure are:

- continued growth in maximum demand. The nature, and drivers, of this growth are described in detail in Chapter 4 of this Regulatory Proposal; and
- to maintain security standards for zone substations consistent with its Network Augmentation Planning and Policy Guidelines and good asset management practice as defined under clause 3.1 of the *Electricity Distribution Code*.

CitiPower has included a list of material major capital projects and programs in the completed Regulatory Template 4.2 and in Chapter 28.

5.4.9 Other information

The RIN requires CitiPower to identify capital works and provide certain other information in relation to the CBD security of Supply Project. The obligations in the RIN are set out in paragraph '*2*'. As paragraph 2 already exists in the RIN (in respect of classification of services), CitiPower understands this to be an error, and refers to the obligations here as being set out in paragraph 16 of the RIN.

Paragraph 16.1 of the RIN requires CitiPower to provide the following in respect of any proposed capital expenditure relating to the CBD Security of Supply Project:

- all documents which were taken into account and relate to its deliverability; and
- an explanation of the proposed deliverability.

CitiPower took into account the *CitiPower Deliverability Plan 2011-15*, which is attached as Attachment C0034, in proposing capital expenditure relating to the CBD Security of Supply Project in respect of the deliverability of that Project. No other documents were taken into account in respect of the deliverability of the CBD Security of Supply Project.

As part of its preparation for this Regulatory Proposal, CitiPower sought the advice of its prime contractor, PNS, as to deliverability of its capital works and maintenance programs and projects. PNS was provided with the proposed expenditure projects and programs, including the CBD Security of Supply Project, and asked to prepare a report as to the deliverability of them. PNS confirmed it had sufficient resources to meet the proposed expenditure program including the CBD Security of Supply Project. It should also be noted that work commenced on the CBD Security of Supply Project in 2009. By the end of 2010, the Project will be reaching its peak deliverability phase. Hence, most of the required resources will be in place before the commencement of the next regulatory control period.

Paragraph 16.2 of the RIN requires CitiPower to identify what works, in relation to CBD security of supply, it has undertaken in the current regulatory control period and the works that it proposes to undertake in the next regulatory control period.

CitiPower's *Melbourne CBD Security of Supply Plan*, of 16 June 2008 (**Plan**) which was prepared and submitted to the ESCV on 16 June 2008 in accordance with clause 3.1A.2 of the *Victorian Electricity Distribution Code* (**Code**), and which was subsequently approved by the ESCV on 18 August sets out:

- the objectives of the CBD Security of Supply Project and the criteria for which those objectives will be measured; and
- the proposed capital works program for achieving the stated objectives (see Table 1 in section 2.7 of the Plan). The Plan also sets out (again, in Table 1) the project timeline for the proposed capital works program and its expected costs (as they were at the time of the Plan's submission to the ESCV) of undertaking those works.

CitiPower attaches a copy of the Plan to this Regulatory Proposal as Attachment C0182.

CitiPower confirms that the Plan remains the basis for the projected work for the CBD Security of Supply Project over the next regulatory control period. There are some minor variations to the Plan as a result of the detailed design work undertaken, however these minor variations do not affect the capital works that were identified in the Plan as comprising the Project and the objectives of the Plan are still being achieved.

Paragraph 16.3 of the RIN requires CitiPower to provide certain other information in relation to the program of works associated with the CBD Security of Supply Project. CitiPower confirms that for the purposes of:

- paragraph 16.3(a)(i) of the RIN the aims and objectives of the CBD Security of Supply Project and the individual capital works comprising the Project are set out in sections 2.2 and 2.3 of the Plan;
- paragraph 16.3(a)(ii) of the RIN, the dates by which the capital works associated with the CBD Security of Supply Project were, or are expected to be, undertaken and completed are set out in section 2.7 of the Plan (subject to the dependencies outlined in section 2.6 of the Plan);
- paragraph 16.3(a)(iii) of the RIN, the costs associated with the CBD Security of Supply Project are captured under a separate function code within CitiPower. In particular, they are reported under Reinforcements for the purposes of the Regulatory Accounts;
- paragraph 16.3(b)(i) of the RIN, as outlined in section 2.3 of the Plan, each of the capital works comprising the CBD Security of Supply Project are necessary to:
  - eliminate multiple transformer ended feeder configurations;
  - improve the 66kV transfer capability between zone substations and terminal stations; and
  - provide remote controlled 66kV switching within CBD zone substations;
- paragraph 16.3(b)(ii) of the RIN, the CBD Security of Supply Project, and the individual works comprising the Project that are detailed in the Plan, have been subject to the most extensive and exhaustive consultation process of any project CitiPower has undertaken to date. The development of options and costs was independently undertaken by SKM, in its *CitiPower Review of CBD Security of Supply and Planning Standards: Updated Final Report dated 22 August 2006*. This report is attached to this Regulatory Proposal as Attachment C0190. Further, those options and a Request for Proposals, calling for further options, was issued on 14 December 2006 on NEMMCO's website. CitiPower's *Request for Proposal, RFP 001/006, Projected Distribution Network Limitations, Melbourne Central Business District Victoria of December 2006* is attached to this Regulatory Proposal as Attachment C0193. CitiPower's Request for

Proposals was followed by a Regulatory Test independently undertaken by NERA and published on NEMMCO's website on 11 April 2007. This NERA report, titled *Melbourne CBD Enhancement: Regulatory Test Analysis, CitiPower dated 5 April 2007*, is attached to this Regulatory Proposal as Attachment C0191.

The Regulatory Test process was then followed by an ESCV inquiry that commenced on 10 May 2007. This inquiry included a review by the ESCV's engineering consultant, Maunsell AECOM, and a full consultation process that concluded in August 2008. The ESCV's *Final Decision CBD Security of Supply* of February 2008 is attached to this Regulatory Proposal as Attachment C0192.

Accordingly, there has been extensive consultation and scrutiny, including by independent experts, of the Project and the individual works comprising the Project that are detailed in the Plan, prior to the acceptance of the Plan by the ESCV in August 2008. Throughout this process no party, including the ESCV and its advisor Maunsell AECOM, identified a more efficient or prudent option to the CBD Security of Supply Project or a more efficient or prudent program of works for undertaking that Project;

- paragraph 16.3(b)(iii) of the RIN, as noted in the Regulatory Test and ESCV inquiry documentation cited in response to paragraph 16.3(b)(ii) above, other options were considered but discounted on the basis of cost;
- paragraph 16.3(b)(iv) and (v) of the RIN, the cost and benefit analysis and results thereof for the CBD Security of Supply Project, and the individual works that comprise the Project, are detailed in the associated Regulatory Test and ESCV inquiry documentation cited above in response to paragraph 16.3(b)(ii) of the RIN;
- paragraph 16.3(b)(vi) of the RIN, the types of solutions required to address security of supply are inherently capital based and, accordingly, the only consideration of the scope to substitute capital expenditure for operating expenditure was in respect of demand-side options to the Project. While proposals were sought from demand side proponents as part of the regulatory test process, no feasible long-terms demand side solution materialised. CitiPower has however proposed a demand side solution to manage the risks in the shorter term until completion of the combined CBD Security, and Metro 2012 Projects in 2013 (see operating expenditure step changes);
- paragraph 16.3(b)(vii) of the RIN, the costing for the Project, and the individual works comprising the Project that are detailed in the Plan, was independently developed by SKM. The costing was subject to further review under the regulatory test process and the ESCV's inquiry which involved its technical advisors, Maunsell AECOM, undertaking a detailed costing review. Some minor updates of the 66kV cable expenditure forecast have since occurred as a result of more detailed design and estimation;
- paragraph 16.3(b)(viii) of the RIN, no contingency factors have been included; and

- paragraph 16.3(b)(ix) of the RIN, the estimated expenditure on the individual works comprising the CBD Security of Supply Project (as detailed in Table 1 in section 2.7 of the Plan) are detailed in Regulatory template 4.4.

Paragraph 16.4 of the RIN requires CitiPower to provide certain information in relation to additional distribution level works required in order to deliver N-1 Secure as required by the ESCV.

For the purposes of 16.4(a)(i), (ii) and (iii) of the RIN, CitiPower provides in Table 5.4 below information relating to the proposed works, the objective of these works (ie how the works contribute to the delivery of N-1 Secure) and the dates that the work has been or is expected to be completed.

Purpose	Option chosen	Commencement and completion dates
To maintain N-1 secure at WA an additional 15MVA required to be transferred away at HV feeder level.	Two new feeders: 1 x WA-MP and 1 x WA-FR.	2008 to 2013
To maintain N-1 secure at LQ an additional 35MVA required to be transferred away at HV feeder level	Three new 12MVA-rated feeders: 2 x MP-LQ and 1 x LQ-JA followed by a future 1 x TP-LQ.	2008 to 2012-14
To maintain N-1 secure at MP an additional 26MVA required to be transferred away at HV feeder level.	Three new 12MVA-rated feeders: 2 x MP-LQ and 1 x MP-JA.	2008 to 2014-15.

Table 5.4 CitiPower's proposed works for the CBD Security of Supply project

For the purposes of 16.4(a)(iii) of the RIN, the load forecasts at each zone substation referred to in Table 5-4 above are included in Regulatory template 6.3.

CitiPower provides the following information for the purposes of:

- paragraph 16.4(b)(i) of the RIN, the distribution works will be undertaken in co-ordination with HV feeder works, included in the reinforcement category of the Submission;

- paragraph 16.4(b)(ii) of the RIN, the project options identified in Table 5.4 are preferred because of their consistency with the overall development plans for the CBD network;

- paragraph 16.4(b)(iii) of the RIN, the costs involved in undertaking the various works set out in Table 5.4 can be derived from the estimated expenditure on the individual works comprising the CBD Security of Supply Project (as detailed in Table 1 in section 2.7 of the Plan) that are set out in Regulatory template 4.4; and

- paragraph 16.4(b)(iv) of the RIN, the efficiency of CitiPower's Security of Supply Project and each of the works comprising the Project, is discussed in response to RIN requirement 16.3(b)(ii). CitiPower believes the extensive and exhaustive process can provide the AER reassurance as to the efficiency of

CitiPower's Security of Supply Project, including in particular the works detailed in Table 5-4 above.

5.5 New customer connections capital expenditure including Customer Contributions

5.5.1 Expenditure forecast for 2011-15

Clause S6.1.1(1) of the Rules, and paragraph 5.2(a)(i) of the RIN, require CitiPower to provide a forecast of its New Customer Connections capital expenditure and Customer Contributions for the next regulatory control period. This forecast is detailed in Table 5.5.

	$'000s (real 2010)					
Expenditure category	2011	2012	2013	2014	2015	Total
New customer connections	104,055	106,159	93,503	91,347	94,071	489,135
Customer contributions	(40,434)	(41,291)	(35,732)	(34,036)	(34,767)	(186,260)
Net new customer connections	63,621	64,868	57,771	57,311	59,304	302,875

Table 5.5: CitiPower's new customer connection capital expenditure forecasts for 2011-15

5.5.2 Relevant key drivers or inputs and key assumptions

The key drivers or inputs and key assumptions that are relevant to the New Customer Connection capital expenditure forecast are:

- forecast of customer numbers;
- labour cost escalators;
- contracts/other cost escalators;
- material cost escalators;
- forecast inflation;
- unit rates;
- expenditure on new customer connections;
- new customer capital contributions; and
- 2010 indexation.

The nature of these key drivers or inputs and key assumptions is discussed in section 5.2.1 of this Regulatory Proposal.

5.5.3 Nature, aims, objectives and distinguishing features

Paragraphs 3.1(a)(i)-(ii) of the RIN require CitiPower to describe the nature of, and aims and objectives for, its New Customer Connections capital expenditure and Customer Contributions as well as the factors that distinguish it from other categories of capital expenditure.

New Customer Connections capital expenditure and Customer Contributions relate to new capital works that are required to service new or upgraded customer connections. This program therefore encompasses works that are:

- undertaken by CitiPower or someone acting on its behalf, such as PNS, as well as works that are undertaken by developers and other service providers, who *'gift'* assets to CitiPower once they have been built to its specified technical standards;
- funded by:
    - CitiPower;
    - customers or developers, where they pay a cash contribution to CitiPower who then arranges for the necessary assets to be built; or
    - customers or developers, where they build the assets and gift them to CitiPower. In this instance, CitiPower reimburses customers and developers for the costs that CitiPower would have incurred had it built the assets required to connect the customer.
- for the following types of assets:
    - new or upgraded customer connection assets;
    - new distribution network assets; and
    - augmentations to the upstream distribution network that directly relate to a new or upgraded customer connection.
- required to provide the following Standard Control Services:
    - connection and augmentation works for new connections;
    - auditing of design and construction;
    - specification and design enquiry;
    - temporary supply services;
    - elective underground service where an existing overhead service exists; and
    - fault tolerance service.

New Customer Connections capital expenditure and Customer Contributions are:

- driven by customers rather than being initiated by CitiPower; and
- influenced by economic conditions and development demographics, including major projects arising from mining, pipelines, generation and agricultural development.

In this way, CitiPower's forecasts of New Customer Connection capital expenditure and Customer Contributions represent what it considers is necessary, for the purposes of clause 6.5.7(a) of the Rules, in order to:

- meet and manage the expected demand for connection services over the 2011-15 regulatory control period; and
- ensure that its distribution system, and connection services, meet relevant quality, reliability, safety and security of supply standards.

In preparing its forecasts of New Customer Connection capital expenditure and Customer Contributions, CitiPower has assumed that it will continue to:

- require Customer Contributions for new connections when it is expected that customers will contribute less in incremental revenue through the payment of DUOS charges than the incremental cost of providing supply; and
- calculate Customer Contributions in accordance with the ESCV's Guideline 14.

For the purposes of paragraph 3.1(a)(ii) of the RIN, CitiPower does not consider that there is any reasonable scope for ambiguity between New Customer Connection capital expenditure and any other expenditure category.

5.5.4 Methodology and supporting documentation

Paragraphs 5.1 of the RIN, and clause S6.1.1(2) of the Rules, require CitiPower to provide information about the methodology by which it has prepared its New Customer Connection capital expenditure and Customer Contribution forecasts.

CitiPower is required to make an offer to connect all new customers, including embedded generators, seeking connection to its distribution network under clause 6 of its *Electricity Distribution Licence*, clause 2.2 of the *Victorian Electricity Distribution Code* and clause 5.3.1(c) of the Rules.

As a result, for the purposes of paragraph 5.1(a)(i) of the RIN, there is no specific approach to network planning and investment evaluation that is relevant to New Customer Connections capital expenditure and Customer Contributions. Rather, these works are purely driven by customers' needs. CitiPower's approach to network planning and investment evaluation generally is discussed elsewhere in this Regulatory Proposal.

The ESCV's Guideline 14 currently regulates connection services. In particular, it:

- makes connection and augmentation works contestable in accordance with CitiPower's licence conditions – CitiPower is required to call for tenders to construct the works from at least two other people who otherwise compete for such work, unless the customer agrees with CitiPower that a tender is not required[12]. This means that customers can elect to use a third party Approved Contractor[13], rather than CitiPower, to undertake the connection work on *'greenfield assets'*; and

- sets out the Customer Contribution provisions in clauses 3.2 and 3.3 of the Guidelines. These clauses specify how CitiPower must calculate Customer Contribution to any new or augmented customer connection. Clause 3.2 of the Guidelines requires that a customer must make a Customer Contribution where it is expected that the incremental cost of the works will exceed the incremental revenue that will be received from the customer over a defined period of time[14].

CitiPower will continue to treat new customer connections in the following manner in the next regulatory control period:

- where CitiPower has funded the works then the associated capital expenditure will be included in the Regulatory Asset Base. This means that CitiPower will continue to recover the return on, and of, this expenditure through DUOS charges;

- where CitiPower receives Customer Contributions from customers and developers but it undertakes the works then these amounts will be netted off CitiPower's capital expenditure that is included in its Regulatory Asset Base; and

- where a third party provider has constructed and funded the works then the new assets will be included in the regulatory asset base at zero value. Where CitiPower pays a rebate to the customer or developer then this cost is included in the Regulatory Asset Base.

This is consistent with the approach that is used in the current regulatory control period.

Accordingly, CitiPower has forecast the:

- New Customer Connection capital expenditure that it will undertake; and

- Customer Contributions that it will receive in relation to new or upgraded connection assets as well as the rebates that it will pay in relation to gifted assets.

These two forecasts are discussed in turn below.

CitiPower notes that, for the purposes of paragraph 5.1(a)(ii) of the RIN, all capital expenditure associated with the AMI rollout is recorded against function codes that are

[12] CitiPower also provides the customer the option of conducting the tender process themselves.

[13] Eligible Approved Contractors are accredited by CitiPower. Customers are required to select an accredited Approved Contractor.

[14] The calculation period is 30 years for residential customers and 15 years for commercial / industrial customers.

specific to the AMI project, as required under Electricity Industry Guideline No.3. All capital expenditure associated with the AMI rollout is therefore separately identified and accounted for, and is not incorporated into capital expenditure for Standard Control Services.

New Customer Connection capital expenditure for 2011-15

CitiPower has prepared annual New Customer Connection capital expenditure forecasts for each year of the next regulatory control period by drawing on historic expenditure at an activity code level within its internal SAP system.

CitiPower recognises 17 separate connection activity types, which can be mapped to the following three categories:

- residential connections – this includes underground and overhead low and medium density residential developments;
- commercial connections – this includes small commercial customer projects to support new or increased load; and
- large connection – this includes medium and large commercial customer projects and subdivision/high rise developments.

These categories align closely with CitiPower's existing network tariff categories[15] and the customer connection data provided by NIEIR report to CitiPower entitled *Electricity Sales and Customer Number Projects for the CitiPower region to 2019*.

For the purposes of preparing its New Customer Connections capital expenditure forecast, CitiPower further distinguishes between two main connection types, being:

- projects less than $300,000 – these projects generally relate to residential connections and commercial connections. These connections comprise around 91 per cent of all non-routine customer connections; and
- projects greater than or equal to $300,000 – these are for *'major projects'* that relate to large customer connections.

For those projects less than $300,000, CitiPower has:

- calculated the 2009 base year New Customer Connections capital expenditure based on a blend of actual[16] and forecast data; and
- indexed the 2009 base year for each year of the next regulatory control period by applying NIEIR's net customer growth forecasts for each network tariff category.

For those projects greater than or equal to $300,000, CitiPower has:

[15] CitiPower has five main tariff categories which can be summarised as residential (or domestic), commercial (energy only), commercial large low voltage, commercial high voltage, commercial sub-transmission.
[16] Actual data is available for half yearly data (January – July)

- calculated the total *'average capital expenditure'* by its internal function codes, based on the 2008 actual expenditure, 2009 actual and estimated expenditure and 2010 forecast expenditure. CitiPower has used three years of data because these larger projects generally take several years to complete; and

- indexed the 2008-10 total *'average capital expenditure'* for each year of the next regulatory control period by applying NIEIR's net customer growth forecasts for each network tariff category[17].

The processes for developing the forecasts for projects less, and greater, than $300,000 are detailed in Figure 5-4 below:

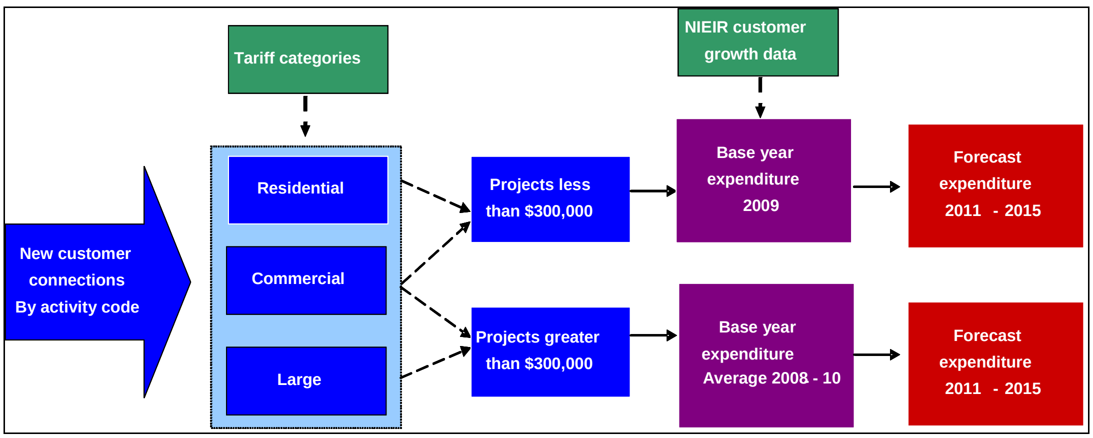

Figure 5-4: New connections expenditure forecast process

Forecast customer contributions for 2011-15

CitiPower generally only knows up to six months in advance what Customer Contributions it is likely to receive from customers, whether in the form of cash or gifted assets. As a consequence, it is not possible to forecast the Customer Contribution for the next regulatory control period based on a bottom up view of the Customer Contributions that it will actually receive.

As a result, CitiPower has forecast its Customer Contributions for the next regulatory control period by determining a 2009 base year. The base year has been calculated by:

- preserving the current proportion, for each internal function code, of Customer Contributions to the New Customer Connection capital expenditure; and

- applying a 40 per cent reduction in the marginal cost of reinforcement (MCR) compared to 2008 levels. This follows the release on 17 July 2009 of the AER's *Formal Decision on Citipower's* (sic) *current approach to charge new customers capital contribution for upstream network augmentation and further consultation*

[17] CitiPower weights the application of the NIEIR growth rates according to network tariff categories (as identified on the basis of activity codes)

on what should be the fair and reasonable charging rates[18]. CitiPower has made this adjustment on a 'without prejudice' basis.

The Customer Contributions, adjusted for the reduction in the MCR for each function code have then been applied to the New Customer Connection capital expenditure forecasts for 2011-15 in order to determine the Customer Contribution forecasts for the same period.

5.5.5 Other information

Paragraph 5.2 of the RIN requires CitiPower to provide certain other information in relation to its historic and forecast Customer Contributions.

Historic and Forecast Customer Contributions

Paragraph 5.2(a)(i) of the RIN requires CitiPower to provide details of its New Customer Connection capital expenditure and its Customer Contributions.

This information is provided in the completed Regulatory Templates 2.1 and 3.1.

Customer Categories for Customer Contributions

Paragraph 5.2(a)(ii) of the RIN requires CitiPower to provide information in relation to the customer categories to which Customer Contributions relate.

The Customer Contributions detailed in the completed Regulatory Templates 2.1 and 3.1 relate to all categories of customers except public lighting customers. Accordingly, CitiPower has specifically excluded public lighting contributions from these completed Regulatory Templates.

Variances between Customer Contributions and Total New Customer Connection capital expenditure

Clause S6.1.1(7) of the Rules requires CitiPower to explain significant variations in forecast capital expenditure from historical capital expenditure. In addition, paragraph 5.2(b)(i) of the RIN requires CitiPower to explain variances of greater than 10 per cent in the proportion of Customer Contributions to gross New Customer Connection capital expenditure for each year of the current and next regulatory control period.

CitiPower estimates that its net New Customer Connection capital expenditure for the 2006-10 regulatory control period will be $170 million ($2010). It is forecasting that this will increase to $303 million ($2010) in the 2011-15 regulatory control period, which is an increase of approximately 78 per cent.

The main factors driving this increase in net New Customer Connection capital expenditure (across all customer categories) are:

[18] Found at: http://www.aer.gov.au/content/item.phtml?itemId=729549 and nodeId=353f5965320bc91dd274c552ce5c1620&fn=AER's%20formal%20decision%20on%20CitiPower%20and%20request%20for%20further%20submissions.pdf

- the 40 per cent reduction in the reduction in the MCR. This translates into a decrease in capital contribution received by customers and a proportionate increase in the net New Customer Connection capital expenditure;
- the introduction of a fault level compliance service in the 2011-2015 regulatory control period. This is a new service designed to manage the future impacts that the connection of any new embedded generators have on the plant ratings. The forecast expenditure associated with this new service has been included in the New Customer Connection capital expenditure forecasts. CitiPower proposes that its costs be recovered from embedded generators with name plate ratings above 100kW through a per kW charge. This is discussed in detail in section 3.2.14 of this Regulatory Proposal;
- development of the former Carlton United Brewery. This project involves augmentation to enable supply of 28MVA at the former Carlton and United Brewery site in Swanston Street, Melbourne to support mixed commercial/residential development;
- an increase in the number of services classified as New Customer Connections. This is discussed in Chapter 3 of this Regulatory Proposal; and
- continued growth in customer numbers. The nature, and drivers, of this growth are described in detail in Chapter 4 of this Regulatory Proposal;

The variations in the proportion of Customer Contributions to gross New Customer Connection capital expenditure for each year of the current and next regulatory control period varies due to those factors listed above, which impact on the forecast New Customer Connection capital expenditure for the 2011-2015 regulatory control period, as well as the mix of projects that are undertaken in any given year.

Depth of connections funded by Customer Contributions

Paragraph 5.2(b)(ii) of the RIN requires CitiPower to explain the depth of connections funded by Customer Contributions.

The ESCV's Guideline 14 sets out the requirements for CitiPower to charge customers for new customer connection and augmentation services. Importantly, Guideline 14 does not contemplate '*deep*' and '*shallow*' connection assets. Rather, Guideline 14 requires that a customer pay a Customer Contribution towards the costs of a connection based on the '*shortfall*' between incremental revenue and incremental cost of the connection. Under this calculation:

- incremental revenue is calculated based on 15 years of DUOS charges for business customers and 30 years of DUOS charges for domestic customers; and
- incremental costs are calculated based on the capital and operating expenditure, over the same timeframe, relating to:

- connection assets, whose use is unique to a specific customer – these assets may be regarded as shallow connection assets but are not formally defined as such by either CitiPower or Guideline 14; and

- network assets, whose use is shared across many customers, albeit that the need for new network assets may be triggered by a new customer connection. These assets may be regarded as deep connection assets but are not formally defined as such by either CitiPower or Guideline 14. The cost of the network assets that is reflected into the Customer Contribution is determined based on the MCR, which is calculated in advance by CitiPower.

  The MCR calculation is based on CitiPower's long term average historical unit cost of upstream network augmentation (indexed for inflation) and is scaled according to a new customer's expected demand. The charge takes account of different levels of connection and the load diversity of the connecting customer. This results in a per MVA cost for each of the following different connection levels for the Businesses network: sub-transmission assets; zone substation bus; high voltage feeder; distribution substation; and low voltage street circuit.

Ultimately, the depth of the connection funded by a Customer Contribution will depend on the characteristics of the customers' connection assets.

Victorian Government's Powerline Relocation Scheme

Paragraph 5.2(c)(i) of the RIN requires CitiPower to identify the extent to which Customer Contributions are attributable to the Victorian Government's Powerline Relocation Scheme in the previous, current and next regulatory control periods.

Under the Victorian Government's Powerline Relocation Scheme, the Victorian Government may fund up to 50 per cent of the cost of placing powerlines underground, or otherwise relocating them, where a community benefit will result.

CitiPower does not receive any funding from the Victorian Government in relation to this scheme. Customers may directly apply for funding where they consider it appropriate and, if successful, the Government makes a payment directly to them.

CitiPower does not:

- require customers to inform it of any payment that they may receive from the Victorian Government under the scheme;
- record any information in relation to payments made by the Victorian Government under the scheme; or
- take any refunds resulting from the scheme into account when calculating the Customer Contributions. All Customer Contributions are calculated in accordance with Guideline 14.

Wind farm related connection capital expenditure

Paragraph 5.2(c)(ii) of the RIN requires CitiPower to identify the extent to which Customer Contributions are attributable to wind farm related connection capital expenditure that is funded under section 15C of the *Electricity Industry Act 2000 (Vic)*.

At the time of submitting this Regulatory Proposal, CitiPower does not have any declared, or proposed, augmentations that relate to facilitating development and construction of a wind energy generation facility for its network, as contemplated by section 15(C)(1) and (2) of the *Electricity Industry Act 2000 (Vic)*.

As a result, CitiPower's forecast Customer Contributions for the 2011-15 regulatory control period do not include any wind farm related connection capital expenditure that is funded under the *Electricity Industry Act 2000 (Vic).*

5.5.6 Why the forecast expenditure is justified

CitiPower is required to make an offer to connect all new customers, including embedded generators, seeking connection to its distribution network. The new customer connection expenditure forecast is therefore required to ensure that CitiPower can deliver the requested works to its customers.

At the time of preparing this Regulatory Proposal, the Ministerial Council for Energy (**MCE**) is undertaking a review of '*Electricity Distribution Network Planning and Connection*'. CitiPower understands that, as part of this review, the MCE will establish a national Customer Contributions framework. At the time of submitting this Regulatory Proposal, the nature and requirements of the future framework have not been finalised. As a result, CitiPower:

- has based its forecast new customer connections and customer contributions for the next regulatory control period on existing arrangements, with an adjustment being made for the AER's impending final decision in relation to the MCR for CitiPower; and
- considers that any changes to its existing Customer Contribution arrangements resulting from the MCE's review should be accompanied by appropriate transitional, and/or cost pass-through, arrangements in order to accommodate any changes that are required from CitiPower's existing practices.

The New Customer Connections capital expenditure and Customer Contributions forecasts included in this Regulatory Proposal are therefore necessary in order to enable CitiPower to meet its current and future obligations to offer connection services to customers upon their request.

5.6 Reliability and Quality Maintained

5.6.1 Expenditure forecast for 2011-15

Clause S6.1.1(1) of the Rules requires CitiPower to provide a forecast of its Reliability and Quality Maintained capital expenditure for the next regulatory control period. This forecast is detailed in Table 5.6.

	$'000s (real 2010)[1]					
Expenditure category	2011	2012	2013	2014	2015	Total
Reliability and quality maintained	56,099	69,357	63,795	69,781	83,030	342,062

Table 5.6: CitiPower's Reliability and Quality Maintained capital expenditure forecasts for 2011-15

5.6.2 Relevant key drivers or inputs and key assumptions

Paragraphs 3.5(a)(i) and 3.5(b) of the RIN require CitiPower to provide information in relation to the key drivers or inputs and key assumptions that are relevant to the Reliability and Quality Maintained capital expenditure forecast.

The key drivers or inputs and key assumptions that are relevant to the Reliability and Quality Maintained capital expenditure forecast are:

- CitiPower's internal documents;
- CitiPower's internal documents are efficient and prudent;
- regulatory change
- labour cost escalators;
- contracts/other cost escalators;
- material cost escalators;
- forecast inflation;
- unit rates; and
- 2010 indexation.

Section 5.2.1 of this Regulatory Proposal provides the information required by paragraph 3.5(b) of the RIN for each of these key drivers or inputs and key assumptions.

CitiPower observes, for the purposes of paragraph 3.5(a)(iv) of the RIN, that there are no considerations relevant to the Reliability and Quality Maintained capital expenditure forecast other than those relevant key drivers or inputs identified above and the matters identified in response to paragraphs 3.5(a)(i) to (iii) of the RIN in this section 5.6 of the Regulatory Proposal.

For the purposes of paragraph 3.5(e) of the RIN, CitiPower notes that spatial peak demand, forecast of customer numbers and expenditure on new customer connections and new customer capital contributions are not relevant to forecast Reliability and Quality Maintained capital expenditure. Reliability and Quality maintained capital expenditure forecasts are not dependent on customer numbers or spatial peak demand, but asset condition. Expenditure on customer connections and new customer capital contribution relate to customer initiated works on the network. The Reliability and Quality Maintained capital expenditure category does not include customer initiated works. Therefore expenditure on new customer connections and new customer capital contributions is not relevant to forecast Reliability and Quality Maintained capital expenditure.

5.6.3 Nature, aims, objectives and distinguishing features

Paragraphs 3.1(a)(i)-(ii) of the RIN require CitiPower to describe the nature of, and aims and objectives for, its Reliability and Quality Maintained capital expenditure as well as the factors that distinguish it from other categories of capital expenditure.

Reliability and Quality Maintained capital expenditure relates to capital works that are required to maintain CitiPower's network performance within acceptable risk levels, as well as to replace assets that have failed or are imminently about to fail. Reliability and Quality Maintained capital expenditure is necessary because with time, network assets age and deteriorate and, if they are not replaced, they may fail or may operate at a sub-standard level. This may result in a reduced level of service reliability and quality.

In this way, CitiPower's Reliability and Quality Maintained capital expenditure forecasts represent what it considers is necessary, for the purposes of clause 6.5.7(a) of the Rules, in order to ensure that its distribution system, and its network services, meet relevant quality, reliability, safety and security of supply standards.

For the purposes of paragraph 3.1(a)(ii) of the RIN, section 5.4.3 of this Regulatory Proposal explains how Reliability and Quality Maintained capital expenditure is distinguished from Reliability capital expenditure. CitiPower does not consider that there is any reasonable scope for ambiguity between Reliability and Quality Maintained capital expenditure and any other expenditure category.

5.6.4 Regulatory obligations

Paragraph 3.1(b)(iii) of the RIN requires CitiPower to identify each regulatory obligation or requirement relevant to its Reliability and Quality Maintained capital expenditure.

CitiPower confirms that the only regulatory obligation or requirement of relevance to its Reliability and Quality Maintained capital expenditure is the *Victorian Electricity Distribution Code*.

5.6.5 Methodology and supporting documentation

Paragraph 3.1(c)(iii) of the RIN, and clause S6.1.1(2) of the Rules, require CitiPower to explain the methodology by which it has prepared its Reliability and Quality Maintained capital expenditure forecasts. In addition, paragraphs 3.1(b), 3.1(c)(iv), 3.2, 3.5(a)(iii)(4) and 3.5(c) require CitiPower to provide information about documents that it has used in preparing its forecasts.

CitiPower applies the following asset management methodologies to its network assets:

- Reliability-Centred Maintenance (**RCM**) – this methodology is generally applied to routine replacement expenditure for smaller items of plant and equipment, such as poles, pole top-equipment, cross arms, insulators and batteries[19]. The RCM approach has regard for the asset age, condition and operating environment; and

- Condition Based Risk Management (**CBRM**) – this methodology is applied to assess the condition of assets, including the risk of the deterioration of major items of plant, which involve significant and lumpy expenditure. This includes assets such as zone substation transformers and switchgear[20].

  The CBRM methodology has been adopted by CitiPower and provides an external validation of CitiPower's asset replacement estimates of major items of plant. The CBRM process is applied by transmission and distribution companies in the United Kingdom[21] as well as in several other countries.

  The CBRM methodology provides for a systematic framework to quantify the current and future condition, performance and risk of assets so that the need for replacement or refurbishment works can be identified and demonstrated. In particular, CBRM analysis allows CitiPower to qualitatively define:

  - asset condition – this is based on a Health Index (**HI**) which is a numeric representation of the condition of the asset[22];

  - asset performance – this identifies the Probability of Failure (**PoF**) of an asset; and

  - risk – this assesses the combination of PoF and the Consequence of Failure (**CoF**) for individual assets.

  Under this methodology, a calculation is made for each individual item of plant and equipment in order to determine the year in which it will reach or exceed a

[19] Where RCM is not appropriate for a particular asset class an alternative risk based approach is adopted in line with CitiPower's Enterprise Risk Management Framework.

[20] Where CBRM is not appropriate for a particular asset class an alternative risk based approach is adopted in line with CitiPower's Enterprise Risk Management Framework.

[21] EA Technology developed CBRM methodology in conjunction with UK transmission and distribution businesses.

[22] It combines information relating to age, environment, duty and specific condition and performance information to give an comparable measure of condition for individual assets.

threshold value of the HI[23]. The methodology identifies a proposed year for the replacement of the asset. This is then reviewed in conjunction with other augmentation and development plans in order to identify opportunities for synergies, such that the replacement schedule can coincide with other major works. This ensures that CitiPower optimises the development of the network, minimises costs and resources and provides better outcomes for customers. The application of CBRM methodology will result in capital expenditure savings in future regulatory control periods by virtue of CitiPower replacing assets in poor condition in the 2011-15 regulatory control period.

The RCM and CBRM methodologies are reflected into the following documents, which CitiPower has taken into account in preparing its Reliability and Quality Maintained forecasts:

- the *Asset Management Framework 2009* – this sets outs CitiPower's various policies, strategies and objectives in relation to maintaining the reliability and quality of its distribution network. It commits CitiPower to best practice maintenance and replacement practices to ensure network risks and performance are effectively managed. This ensures that:

    - the risk of condition based and age related failures is minimised; and

    - network assets provide adequate, reliable and safe supply of electricity of appropriate quality.

    CitiPower*'s Asset Management Framework 2009* supports its overall corporate strategies, goals and objectives and is moving towards being consistent with PAS 55-1, which is the internationally recognised standard of asset management.

- *Network Asset Management Plans* – these Plans set out CitiPower's detailed understanding of the nature and condition of its assets, which have been categorised into 30 asset groups. In particular, these Plans set out detailed information on the age profile, condition, deterioration rate and performance of its assets;

- *Specific Focus Plans and Strategies* – these Plans describe CitiPower's overall approach to planning and managing its major network elements that are not covered by asset management plans. These Plans are:

    - specific strategies required for a group of assets or local geographic areas where the general asset management plans may not be adequate;

    - strategies that impact on the asset management plans (ie bushfire mitigation strategy plan); and

    - supplementary or supporting strategies or plans.

[23] This is based on the health index at Year 0 (2009) and uses the ageing factor.

- *Network Asset Management Policies* – these policies underpin, and give effect to, the Network Asset Management Plans. These Policies relate to individual assets or asset classes and provide detailed instructions in relation to:
    - maintenance plans, condition monitoring, inspection requirements and assets replacement and renewal for the purposes of optimising the whole of life costs and performance associated with the asset; and
    - under what circumstances capital works should be carried out, including replacement and life extension as well as condition monitoring and maintenance activities.

  Network Asset Management Policies are consistent with, and are supported by, broader strategies and frameworks.

  CitiPower's Asset Management Policies give effect to the Network Asset Management Plans. The policies provide detailed work instructions in relation to routine works for small and large network assets, including condition monitoring, inspection requirements and asset replacement and renewal. This is designed to optimise the whole of life costs associated with specific assets registered in the works management system (**SAP system**)[24].

CitiPower has an information management system that contains detailed information about CitiPower's asset population, in particular:

- the condition of assets, including the defect and deterioration rate; and
- the capital works undertaken and the outturn costs of the capital works.

This system is configured to:

- allow records to be viewed at all times in order to provide a robust platform for the extraction of asset information;
- apply the requirements of the various Asset Management Policies against the relevant assets in order to schedule and plan replacement and maintenance capital works; and
- enable CitiPower's assets to be maintained in accordance with relevant standards and specifications.

The information in this information system, together with scheduled work for large plant and equipment (ie non-routine works for zone substation transformers and switches) as identified under CBRM, allows CitiPower annually to prepare ten year forecasts for Reliability and Quality Maintained capital expenditure. This is based on:

[24] The SAP system registers and records information relating to network assets including the type and nature of assets (age, condition etc)

- physical units of capital works that it is required to undertake in order to maintain assets in accordance with Asset Management Policies and Schedule of Works developed, in accordance with the CBRM method; and

- the current average cost of undertaking physical units of work (ie similar projects and capital work programs). This is estimated on the basis of actual historical costs as recorded in the information system.

There are two main areas of investment in CitiPower's reliability and quality maintained capital expenditure forecast for 2011-15 regulatory control period being: investment to reduce fault levels where they exceed plant ratings; and replacement of plant and equipment.

Investment required to reduce the fault levels where they exceed plant ratings

Maintaining fault levels at or below plant and equipment ratings has become an increasing challenge for CitiPower over the current regulatory control period due to the introduction of Federal and State Government climate change policies which seek to encourage greater investment in embedded generation. In particular, the national *NABERS* building energy efficiency rating system, and the City of Melbourne 1200 Project (*Zero Net Emissions by 2020*), have attracted investment in significant distributed generation connected to the CitiPower distribution system.

These policies have resulted in the CitiPower experiencing a greatly increased, and largely unanticipated, number of connection enquiries and applications for distributed generation since the last regulatory price reset.

CitiPower is required to make an offer to connect all new customers, including embedded generators, seeking connection to its distribution network under clause 6 of its *Electricity Distribution Licence*, clause 2.2 of the *Victorian Electricity Distribution Code* and clause 5.3.1(c) of the Rules.

CitiPower's distribution systems has, however been planned and developed having regard for the traditional flow of electricity from the transmission network to the end customer via the distribution system. This historic development has been very efficient in optimising the utilisation of plant fault levels, co-ordinated with the efficient provision of zone substation capacity. The parallel connection of distributed generation to the existing distribution system requires electricity to flow in two directions - to the end customer for consumption and back into the network when the user is exporting excess generation capacity. Distributed generation connects to the distribution system contributing to the fault level energy that will flow into the local network when a localised network fault occurs.

Key equipment installed on the distribution system is designed with a maximum fault level limit. Exceeding the equipment's designed fault level limit will increase the risk to the reliability and safety of the distribution system.

While the *Victorian Electricity Distribution Code* does not specifically place obligations on CitiPower to maintain fault levels within set levels, it does require it to comply with good asset management practices. CitiPower interprets this to include the management of fault levels on the network. This means that CitiPower must have regard for maintaining fault levels within safe limits that are consistent with the provision of a reliable and secure supply of electricity to their customers. Clause 7.8 of the Code also requires that embedded generators design and operate their plant so as not to cause fault levels on the distribution network to increase above those specified in table 5 of the Code.

Currently, CitiPower manages fault levels by a short term strategy of opening selected zone substation circuit breakers to allow fault levels to drop. CitiPower recognises that opening selected circuit breakers in this manner can potentially undermine the security of the network and increase supply interruptions. In a letter from the ESCV dated 17 October 2008, the ESCV advised that:

> *'It is apparent that in order to keep fault current levels within plant ratings, CitiPower is operating a number of zone substations not in normal configuration, resulting in reduced level of security of supply to its customers. This operational practice may not be consistent with clause 5.2 of the Electricity Distribution Code.'*

CitiPower emphasises that while managing fault levels by opening circuit breakers to allow fault levels to drop is an acceptable and viable short term solution, it is not an acceptable long term solution. CitiPower emphasises that it adopted this solution over the current regulatory control period in order to facilitate the unforseen increased connection of embedded generators resulting from Government policies introduced during the current regulatory control period.

In order to determine the most efficient and prudent long term approach to managing fault level issues caused by existing embedded generators connected to its distribution network, CitiPower engaged Sinclair Knight Merz (**SKM**) to undertake analysis of different investment options to mitigate fault levels. These options are set out in SKM's report of 5 May 2009 entitled *Fault level Mitigation Issues Paper: Embedded Generation in CitiPower Distribution System*, which has been provided to the AER at Attachment C0186 of this Regulatory Proposal.

Based on its own analysis of the different options presented in SKM's Report, CitiPower proposes to mitigate fault level exceedances by installing series reactors within terminal stations and key zone substations during the 2011-2015 regulatory control period. The nature of this investment is discussed in detail in SKM's later report *Accommodating Distribution Generation in the CitiPower Network*, dated October 2009 (see Attachment C0002).

CitiPower believes that this is the most efficient and prudent long term solution to managing fault levels issues caused by existing generators connected to its distribution system.

The cost of this investment is forecast to be approximately $75 million ($2010) over the 2011-15 regulatory control period, and will allow the currently open bus-tie circuit breakers to be operated *'closed'*, thus maintaining network security at the current level of embedded generation.

As discussed in section 3.2.14 of this Regulatory Proposal in order to continue to manage fault level issues that will arise due to the connection of additional new embedded generators to its distribution network, CitiPower proposes to introduce a new fault level compliance service fee in the next regulatory control period. This fee will be classified as a Standard Control Service and the associated expenditure will be included in CitiPower's New Customer Connection capital expenditure forecasts.

Replacement of plant and equipment

Over the 2011-2015 regulatory control period CitiPower will invest in the replacement of plant and equipment such as:

- secondary plant and equipment due to planned replacements, faults or non-repairable breakages within zone substations and the distribution network; and
- high and low voltage switches and switch gear including air break switches, gas switches, metal clad switches and ring main units that are considered defective or at the end of their serviceable life.

This follows the commencement of a detailed schedule of works in 2010 which will continue throughout the next regulatory control period.

CitiPower will also undertake increased volumes of routine replacement programs of: poles; cross arms on sub transmission, high voltage and low voltage overhead lines identified from routine asset inspection; and conductors on overhead and underground sub-transmission high voltage and low voltage cable. The increased volume of these programs over the next regulatory control period is largely due to:

- an increase in the average service age of these assets, which is leading to an increasing risk of higher failure rates; and
- an increase in the class three pole population due to increased service age. Currently, the dominant pole classes are from the 1950 and 1960.

CitiPower will continue to undertake routine replacement expenditure relating to other smaller items of plant and equipment, such as pole top-equipment, insulators and batteries over the next regulatory control period.

A listing of material major capital projects relating to Reliability and Quality Maintained is provided in Regulatory Template 4.2.

5.6.6 Other information

Paragraph 3.5 of the RIN requires CitiPower to provide certain other information in relation to its Reliability and Quality Maintained capital expenditure.

Weighted average remaining life forecasts

Paragraph 13.1 of the RIN required CitiPower to provide certain information in relation to weighted average remaining life forecast in table 2C of the Regulatory Template 6.2.

CitiPower has used a modelling approach to calculate the weighted average remaining life of assets used to populate table 2C of the Regulatory Template 6.2. The model was developed and provided by PB. This model, including the calculations contained in the model, is provided at Attachment C0183 of this Regulatory Proposal,

This modelling approach involved:

- splitting the assets into categories;
- applying an age profile to each of the asset categories;
- applying an asset life to each of the asset categories; and
- then calculating the average remaining life using this information.

The average remaining life has been weighted by the relative replacement cost of the asset category. For those assets that have already reached the end of their life the modelling assumes the assets will be replaced over the regulatory period along with other assets that will reach the end of their nominal life during the regulatory period. The modelling also takes into account high level assumptions of the condition of assets.

The result of the modelling is a theoretical forecast of remaining asset life. The remaining life forecast has been prepared independently from the replacement capital forecast and is not directly linked to the forecast capital expenditure replacement program for the 2011-15 regulatory control period proposed by CitiPower in this Regulatory Proposal.

Asset failure rates

Paragraph 3.5(a)(ii) of the RIN requires CitiPower to provide information about its asset failure rates during both the previous and current regulatory control periods.

CitiPower interprets asset failure to mean equipment that is unfit for service and is therefore unable to perform it primary function. This includes assets that have failed in service, or have *'broken down'*, and/or which must be replaced or refurbished as a priority.

CitiPower does not have, and accordingly can not provide, asset failure rates for the previous regulatory control period or the 2009 (full year) or 2010 regulatory years.

CitiPower provides the following asset failure information in relation to large plant and equipment, poles and cross-arms:

- *large plant and equipment* – this includes circuit breakers, transformers and transformer tap changers. The failures rates in Table 5.7 relate to instances, classified as 'breakdowns', where the equipment or plant is not able to perform its intended function and must therefore be addressed. Breakdowns are distinct from defects and corrective maintenance, as they are a direct result of scheduled inspections and/or testing. Once a breakdown has been identified, a *'Breakdown*

Notification' is raised and recorded in the works management system. An example of a breakdown is a circuit breaker that cannot be latched closed.

Large plant and equipment	2004	2005	2006	2007	2008
Circuit breakers failures – break downs (11kV, 22kV, 66kV)	8	11	6	25	6
Transformer failures	22	10	20	36	10
Transformer tap changer failures	10	7	16	3	11

Table 5.7L Large plant and equipment failure rates

- *poles* – the pole failure rates reported in Table 5.8 relate to:
  - total poles reclassified from serviceable to limited life. Limited life poles are those that have been assessed as being at a certain diminished condition with a limited life remaining. These poles are, however, considered safe and can remain in service until they are replaced;
  - total poles failed in-service actioned as a fault – these poles have failed mechanically (ie broken), typically due to rot or termites and have therefore interrupted power supply. These poles must be replaced with new poles immediately;
  - total unserviceable poles actioned as a priority 1 (**P1**) - these poles are assessed as requiring attention within 24 hours. The assessment is generally made during the cyclic asset inspection process of distribution lines. These poles are replaced or reinforced (staked) where possible; and
  - total unserviceable poles actioned as a priority 2 (**P2**). These poles, which form the majority of CitiPower's pole related work, are assessed as requiring action within 18 weeks under normal routine maintenance. The assessment is generally made during the cyclic asset inspection process for distribution lines. These poles are either replaced or reinforced (staked) where possible.

Inspection Year	Total Poles Reclassified from Serviceable to Limited Life	Total Poles Failed In-Service Actioned as a Fault	Total Unserviceable Poles Actioned as a (Priority 1)	Total Unserviceable Poles Actioned as a (Priority 2)
2004	741	-	24	309
2005	896	-	5	318
2006	1,248	-	4	140
2007	1,104	-	1	171
2008	1,634	3	17	426
Total	5,623	3	51	1,364

Table 5.8: Pole failure rates

- *cross-arms* – the cross-arm failures rates reported in Table 5.9 relate to:
  - cross-arms that have failed in-service – this relates to cross arms that have failed mechanically (broken) typically due to weathering and which have therefore caused a power supply interruption;
  - P1 – this relates to cross arms that are assessed as requiring replacement within 24 hours. The assessment is made as part of the cyclic asset inspection process for distribution lines and is made in line with set criteria; and
  - P2 – this relates to cross arms that are assessed as requiring replacement within 18 weeks. The assessment is made as part of the cyclic asset inspection process for distribution lines and is made in line with set criteria.

	Crossarms failed in-service (Broken)	P1	P2	Total
2004	0	28	161	189
2005	0	25	588	613
2006	0	10	456	466
2007	0	8	464	472
2008	4	11	643	658
Total	4	82	2,312	2,398

Table 5.9: Cross arm failure rates

Paragraph 3.5(b) of the RIN requires CitiPower to provide certain information in relation to whether and how asset failure rates were taken into account in estimating Reliability and Quality Maintained capital expenditure and the sensitivity impact of asset failure rates on forecast Reliability and Quality Maintained capital expenditure.

The historical asset failure rates were not used directly to estimate forecast capital expenditure. The historic failure rates are the outturn results of current asset management policies, which are used as the basis for estimating forecast capital expenditure for the 2011-15 regulatory control period. This is discussed in section 5.6.4 of this Regulatory Proposal.

This means that outturn failure rates have indirectly impacted the Reliability and Quality Maintained forecast capital expenditure. This means that the sensitivity of Reliability and Quality Maintained capital expenditure to asset failure rates is reflected in the sensitivity of Reliability and Quality Maintained capital expenditure to the asset management documentation. This is discussed in Table 5.2 of this Regulatory Proposal.

CitiPower anticipates that failure rates in the next regulatory control period will not be materially different from those reported in the current regulatory control period, albeit that there will likely be a small upward trend in the number of poles being reclassified from *'Serviceable'* to *'Limited Life'*. This reclassification has been reflected in the capital expenditure forecast.

Age based compared to condition based capital expenditure

Paragraphs 3.5(a) and 3.5(b) of the RIN requires CitiPower to provide information about its approaches to aged based, compared to condition based, Reliability and Quality Maintained capital expenditure.

As discussed in section 5.6.4 above, CitiPower applies two main approaches to managing and maintaining its network assets to ensure that:

- network performance is maintained within acceptable risk levels;
- assets that have failed or are imminently about to fail are replaced; and
- quality and reliability of supply are maintained at appropriate levels.

These two approaches are the:

- RCM methodology; and
- CBRM methodology.

These are primarily condition based methodologies, however RCM, which applies to the routine replacement of smaller items of plant and equipment, does have regard for, amongst other things, the age of the asset and its operating environment. As CitiPower applied condition based asset management in the current regulatory control period, and will continue to apply such an approach in the next regulatory control period, there will be no incremental impact on forecast Reliability and Quality Maintained capital expenditure from the condition based approach. However, as noted above in section 5.6.4, the introduction of CBRM methodology to validate asset replacement of large plant and equipment will result in a relative increase in Reliability and Quality Maintained capital expenditure over the 2011-15 regulatory control period.

Regarding the sensitivity of forecast Reliability and Quality Maintained capital expenditure to age based, compared to condition based, replacement, CitiPower notes that Reliability and Quality Maintained capital expenditure is not directly determined by, and is therefore not directly sensitive to, age-based replacement. This is because CitiPower primarily applies condition based methodologies.

Replacement and refurbishment based capital expenditure

Paragraphs 3.5(a) and 3.5(b) of the RIN requires CitiPower to provide information about its approaches to replacement, compared to refurbishment based, Reliability and Quality Maintained capital expenditure.

CitiPower considers whether to replace or refurbish assets based by assessing the relative costs and benefits of doing so. CitiPower predominately relies on asset replacement, rather than refurbishment, particularly for the secondary systems and large items of plant and equipment. This is because:

- secondary system assets - asset types and families, such as electro-mechanical protection relays, generally have a defined life after which they become obsolete and are no longer supported by the manufacturer; and

- large items of plant and equipment – CitiPower applies the CBRM methodology to assets such as zone substation transformers and switchgear. This methodology is focused on the optimised replacement of assets, although it does have regard for refurbishment where appropriate.

However, CitiPower does have some refurbishment programs, including in relation to:

- poles – these are programs to reinforce and stake poles to extend their useful lives;

- cables – this includes cable rejuvenation trials to determine whether this is a feasible and cost effective way to extend the useful life of cables; and

- oil – this includes oil regeneration and/or dehydration practices to treat transformer oil as a means of extending plant life, where applicable.

In relation to how and whether replacement, in comparison to refurbishment, was taken into account in developing CitiPower's Reliability and Quality Maintained forecast expenditure, CitiPower notes that this is set out in section 5.6.4 of this Regulatory Proposal.

CitiPower will continue to rely mostly on asset replacement, rather than refurbishment, in the forthcoming regulatory control period, therefore, there will be no incremental impact on forecast Reliability and Quality Maintained capital expenditure from this approach.

Regarding the sensitivity of forecast Reliability and Quality Maintained capital expenditure to replacement, in comparison to refurbishment, CitiPower notes that forecast Reliability and Quality Maintained capital expenditure is not directly determined by refurbishment, and is therefore not directly sensitive to, refurbishment based expenditure. As described in section 5.6.4 above, forecast Reliability and Quality Maintained capital expenditure is sensitive to replacement expenditure.

Asset replacement models developed by or for CitiPower

Paragraphs 3.5(a)(iii)(3) and 3.5(c) of the RIN require CitiPower to provide information about its asset replacement models that are relevant to its Reliability and Quality Maintained capital expenditure.

CitiPower does not have any software based replacement models. It uses the RCM and CBRM methodologies to manage and maintain its network assets to ensure that network performance is maintained within acceptable risk levels.

RCM does not have any associated software based model and the CBRM is based on a spreadsheet model, which captures information about, amongst other things:

- the number, age and location of assets including zone substation, transformers, switchgear – this data has been largely sourced from the GIS and works management systems;
- the cost of replacements and repairs – this information has been derived based on the current average costs of replacing similar plant and equipment (sizes and/or ratings of plant taken into account) as well as recent quotes for new equipment; and
- the condition and risk data for each major item of plant – this data has been sourced in part from the works management system (particularly in relation to plant condition test and inspection results relating to oil, bushings and insulation resistance). Other condition and risk data has been prepared internally, based on physical assessments undertaken in accordance with processes approved by EA Technology. EA Technology also reviewed and validated the condition assessments results.

The CBRM methodology was developed, and supplied to CitiPower, by EA Technology. CitiPower applies the CBRM methodology in order to provide external validation of its internal asset condition assessments.

Interaction between Reinforcement and Reliability and Quality Maintained capital expenditure

Paragraph 3.5(d) of the RIN requires CitiPower to explain how any proposed Reinforcement capital expenditure forecasts associated with the replacement of assets before the end of their technical lives have been taken into account in the proposed Reliability and Quality Maintained capital expenditure forecasts.

The proposed Reliability and Quality Maintained capital expenditure, particularly for large items of plant and equipment identified under the CBRM methodology, is reviewed in conjunction with CitiPower's augmentation and development plans. This is done in order to identify opportunities for synergies, such that the Reliability and Quality Maintained capital expenditure schedule can be coincided with other major reinforcement works where it is feasible, safe and efficient to do so.

This ensures that CitiPower optimises the development of its network, minimise costs and resources and provides better outcomes for customers.

Variances in Reliability and Quality Maintained capital expenditure

Clause S6.1.1(7) of the Rules requires CitiPower to explain significant variations in forecast capital expenditure from historical capital expenditure. In addition, Paragraph 3.5(b)(iii) of the RIN requires CitiPower to explain variances between forecast and actual Reliability and Quality Maintained capital expenditure.

CitiPower estimates that its Reliability and Quality Maintained capital expenditure for the 2006-10 regulatory control period will be $168 million ($2010). It is forecasting that this will increase to $342 million ($2010) in the 2011-15 regulatory control period, which is an increase of approximately 103 per cent.

The main factors driving this increase in Reliability and Quality Maintained capital expenditure are:

- significant expenditure in relation to management of fault levels on the network;
- increased replacement of large plant and equipment, including those that are considered defective or at the end of their serviceable life. The implementation of CBRM methodology during the current regulatory control period has enabled CitiPower to verify the need to replace large plant and equipment; and
- increased routine replacement expenditure on smaller items of plant and equipment including poles; cross arms; and conductors. This is largely due to an increase in the average service age of these assets, which is leading to an increasing risk of higher failure rates.

CitiPower has included a list of material major capital projects in the completed Regulatory Template 4.2 and Chapter 28.

5.6.7 Why the forecast expenditure is justified

CitiPower's forecast Reliability and Quality Maintained capital expenditure seeks to ensure that, over the next regulatory control period, it can:

- address all condition-based deterioration and defects before assets fail; and
- replace, as quickly and as efficiently as possible, all assets that have failed in service.

This is necessary in order to:

- meet quality, reliability, safety and security of supply to customers, as well as to minimise safety risks to the public and CitiPower's staff;
- manage the risks of asset failures in service and the occurrence of dangerous electrical events; and
- maintain the condition of its assets in line with its Asset Management Plans and Polices in order to ensure that its future aged replacement expenditure can be managed in an orderly manner.

This is consistent with the capital expenditure objectives in clause 6.5.7(a) of the Rules, in particular the need to ensure that CitiPower's distribution system, and its network services, meet relevant quality, reliability, safety and security of supply standards.

5.7 Environmental, safety and legal capital expenditure

5.7.1 Expenditure forecast for 2011-15

Clause S6.1.1(1) of the Rules requires CitiPower to provide a forecast of its Environmental, Safety and Legal capital expenditure for the next regulatory control period. This forecast is detailed in Table 5.10 below.

	$'000s (real 2010)					
Expenditure category	2011	2012	2013	2014	2015	Total
Environmental, safety and legal	4,397	3,980	4,051	3,905	4,121	20,454

Table 5.10: CitiPower's environmental, safety and legal capital expenditure forecasts for 2011-15

5.7.2 Relevant key drivers or inputs and key assumptions

Paragraphs 3.7(a)(i) and 3.7(b) of the RIN require CitiPower to provide information in relation to the key drivers or inputs and key assumptions that are relevant to the Environmental, Safety and Legal capital expenditure forecast.

The key drivers or inputs and key assumptions that are relevant to the Environmental, Safety and Legal capital expenditure forecast are:

- regulatory change;
- labour cost escalators;
- contracts/other cost escalators;
- material cost escalators;
- forecast inflation;
- unit rates; and
- 2010 indexation.

Section 5.2.1 of this Regulatory Proposal provides the information required by paragraph 3.3(b) of the RIN for each of these key drivers or inputs and key assumptions.

CitiPower observes, for the purposes of paragraph 3.7(a)(vi) of the RIN, that there are no considerations relevant to the Environmental, Safety and Legal capital expenditure forecasts other than those relevant key drivers or inputs identified above and the matters identified in response to paragraphs 3.7(a)(i) to (v) of the RIN in this section 5.7.

For the purposes of paragraph 3.7(c) of the RIN, CitiPower notes that the assumptions regarding key spatial peak demand, CitiPower's internal documents, forecast of customer numbers, expenditure on new customer connections and new customer capital contributions are not relevant to forecast Environmental, Safety and Legal capital expenditure. Environmental, Safety and Legal capital expenditure forecasts are not dependent on customer numbers, spatial peak demand or CitiPower's Planning Guidelines or asset management documents but are dependent on applicable environmental, electrical safety regulatory and other Victorian and national legislative obligations. Expenditure on customer connections and new customer capital contribution relate to customer initiated works on the network. The Environmental, Safety and Legal capital expenditure category does not include customer initiated works. Therefore expenditure on new customer connections and new customer capital contributions is not relevant to forecast Environmental, Safety and Legal capital expenditure.

5.7.3 Nature, aims, objectives and distinguishing features

Paragraphs 3.1(a)(i)-(ii) of the RIN require CitiPower to describe the nature of, and aims and objectives for, its Environmental, Safety and Legal capital expenditure as well as the factors that distinguish it from other categories of capital expenditure.

Environmental, Safety and Legal capital expenditure relates to capital works that CitiPower undertakes in order to ensure that it is compliant with all applicable environmental, electrical safety regulatory and other Victorian and national legislative obligations. In particular, it relates to expenditure required to comply with requirements from:

- Energy Safe Victoria (**ESV**) – ESV regulates the safe operation and maintenance of CitiPower's network; and
- the Victorian Environmental Protection Authority (**EPA**) - the EPA regulates a number of areas, through Acts, regulations, State Environment Protection Policies (**SEPPs**) and waste management policies (**WMPs**), that impact directly on CitiPower. These include noise mitigation, oil containment and drainage and the handling and disposal of asbestos and bushfire mitigation.

In this way, CitiPower's Environmental, Safety and Legal capital expenditure forecasts represent what it considers is necessary, for the purposes of clause 6.5.7(a) of the Rules, in order to:

- comply with all applicable regulatory obligations or requirements associated with the provision of Standard Control Services; and
- ensure that its distribution system, and its network services, meet relevant quality, reliability, safety and security of supply standards.

For the purposes of paragraph 3.1(a)(ii) of the RIN, CitiPower notes that the main distinguishing factors between Environmental, Safety and Legal capital expenditure and Reliability and Quality Maintained capital expenditure are that Reliability and Quality Maintained capital expenditure relates to works that are necessary in light of particular assets' age and/or level of deterioration, whereas Environmental, Safety and Legal capital expenditure relates to capital works that CitiPower undertakes in order to ensure that it is compliant with all applicable environmental, electrical safety regulatory and other Victorian and national legislative obligations. CitiPower does not consider that there is any reasonable scope for ambiguity between Environmental, Safety and Legal capital expenditure and any other expenditure category.

5.7.4 Methodology and supporting documentation

Paragraph 3.1(c)(iii) of the RIN, and clause S6.1.1(2) of the Rules, require CitiPower to explain the methodology by which it has prepared its Environmental, Safety and Legal capital expenditure forecasts. In addition, paragraphs 3.2, 3.1(c)(iv), 3.7(a) and 3.7(d) require CitiPower to provide information about relevant regulatory obligations or requirements that it has had regard for in preparing its forecasts.

The safety of its employees, contractors and the public, and avoiding adverse environmental impacts, are of paramount importance to CitiPower's operations. CitiPower's approach to forecasting expenditure required to meet its safety and environmental obligations is detailed below.

Environmental

Key environmental issues that CitiPower needs to manage include:

- noise control;
- containment and drainage of oil in zone substations; and
- asbestos management.

These are discussed in turn.

CitiPower observes, for the purposes of paragraph 3.7(c) of the RIN, that while the *Electrical Safety (Bushfire Mitigation) Regulations 2003* apply to it, bushfire mitigation is not a key environmental issue for CitiPower, since the capital expenditure required to comply with these regulations is negligible.

Noise control

The *State Environment Protection Policy (Control of Noise from Commerce, Industry and Trade) No. N-1* (**SEPP (N-1)**) regulates the impact of noise emissions generated from CitiPower's distribution assets on surrounding areas. CitiPower has an Environment Improvement Plan (**EIP**)[25] to assist it in complying with noise related obligations. The underlying philosophy of the EIP is continuous improvement.

CitiPower's zone substation program of works over the 2011-2015 regulatory control period has been informed by external noise consultants who reviewed all of CitiPower's zone substations for compliance with SEPP (N-1) in 2003.

CitiPower will undertake the highest priority works over the next regulatory control period. This involves building enclosures for the following zone substations:

[25] CitiPower prepared the noise EIP on a voluntary basis for the purpose of satisfying the requirements of the State Environment Protection Policy (Control of Noise from Commerce, Industry and Trade) No. N-1 (SEPP (N-1).

- Brunswick Zone Substation – CitiPower plans to commence the works in 2011;
- Northcote Zone Substation – CitiPower plans to commence the works in 2012;
- Kew Zone Substation – CitiPower plans to commence the works in 2013;
- Flinders/Ramsden Zone Substation – CitiPower plans to commence the works in 2014; and
- Balaclava Zone Substation – CitiPower plans to commence the works in 2015.

CitiPower will also continue to undertake distribution substation noise mitigation over the 2011-2015 regulatory control period. Levels of work will be consistent with current levels in the 2006-10 regulatory control period whereby CitiPower replaces around two distribution substations per year.

Forecast expenditure in the next regulatory control period is based on the current average cost of undertaking similar physical units of work in the 2006-10 regulatory control period.

Containment and drainage of oil in zone substations

There are a range of regulatory and legislative obligations which regulate the containment and drainage of oil filled equipment, namely:

- EPA Bunding Guideline 1992 Publication 347;
- Australian Standards (**AS**) - Storage and handling of flammable and combustible liquids 1993;
- Electricity Supply Association of Australia (**ESAA**) Guidelines for Oil Containment in the Electricity Supply Industry; and
- EPA SEPP (Waters of Victoria) and (Groundwaters of Victoria) – these policies regulate the release of contaminants, including oil, in storm water drains.

CitiPower has *Oil Containment Guidelines* (**Guidelines**) to assist it in complying with these obligations. These Guidelines provide a basis for CitiPower's ten year work program for upgrading or replacing oil bunds at zone substations and retrofitting drainage at zone substations. This ongoing program of works was developed on the basis of an independent risk rating report of CitiPower's zone substations. Further, CitiPower undertakes an annual audit of all its zone substations for the potential risk to the environment resulting from oil spillage. This annual audit also adds to the annual works program.

Forecast expenditure in the next regulatory control period is based on the current average cost of undertaking similar physical units of work in the 2006-10 regulatory control period.

Asbestos management

The Occupational Health and Safety (**OHS**) Regulations 2007 (**OHS Regulations**) and the Environment Protection (Industrial Waste Resource) Regulations 2009 regulate the storage and disposal of asbestos materials.

CitiPower has an *Asbestos Management Manual - 14-25-M0004* to assist it in complying with asbestos related obligations. The Manual provides a set of procedures to be followed when planning for asbestos work and working with and removing materials containing asbestos. This Manual has been developed to ensure the health of employees, members of the public and the environment is not compromised in undertaking such work.

In accordance with the requirements of the *OH&S Regulations 2007*, CitiPower undertakes an external asbestos condition audit every five years. The outcomes of this audit are recorded in CitiPower's asbestos risk register, which in turn informs the program of works for the following five years. CitiPower will commence actioning the outcomes of the most recent audit in 2009 on a prioritised basis. The results of the most recent audit will result in business as usual expenditure over the next regulatory control period.

Forecast expenditure in the next regulatory control period is based on the current average cost of undertaking physical units of work. The physical units of work required in the 2011-15 regulatory control period are driven by the five year program of works.

Safety

CitiPower has extensive safety obligations under the Electrical Safety Act (Victoria) 1998 and associated Regulations, in particular the Electricity Safety (Network Assets) Regulations 1999 and the Electricity Safety (Management) Regulations 1999.

The *Electrical Safety Amendment Act 2007* defines the term Major Electricity Company, which includes CitiPower, as a regulated distribution company, and includes the requirement that CitiPower develop an Electricity Safety Management Scheme that sets out how it will operate and maintain its network in a safe manner. CitiPower is required to submit this Electricity Safety Management Scheme to ESV for its formal approval by 31 December 2009. This is the first time that there has been a mandatory requirement for CitiPower to develop such a scheme for approval by ESV. CitiPower prepared its existing Electricity Safety Management Scheme on a voluntary basis[26].

CitiPower has a number of existing safety management plans under its existing Electricity Safety Management Scheme, which set out set a program of works in order to achieve compliance with relevant obligations. While only one of these safety management plans, *Aerial Service Line Clearances*, has been formally approved, CitiPower undertakes the work programs outlined in all of its safety management plans. This is consistent with ensuring public and staff safety and good corporate governance. CitiPower's approved *Aerial Service Line Clearances Safety*

[26] The existing Electricity Safety Management Scheme was approved by the an Order in Council on 26 October 2004 but has never been approved by ESV.

Management Plan, which is provided at Attachment C0054 to this Regulatory Proposal, sets out the nature and scope of the aerial service line clearance exemption.

Forecast expenditure in the next regulatory control period is based on the current average cost of undertaking the program of works in the 2006-10 regulatory control period. The works program for the 2011-15 regulatory control period is derived from CitiPower's existing safety management plans and will largely reflect a continuation of the work program in the current regulatory control period.

5.7.5 Other information

Paragraph 3.7 of the RIN requires CitiPower to provide certain other information in relation to its Environmental, Safety and Legal capital expenditure.

Variations and exemptions from regulations

Paragraphs 3.7(a)(iii), 3.7(b) and 3.7(e)(i)-(iii) of the RIN require CitiPower to provide information about variations and exemptions from Regulations that have been granted during the previous and current regulatory control periods.

CitiPower has an Electricity Safety Management Scheme (**ESMS**), which came into effect in 2004[27]. CitiPower prepared its ESMS in accordance with clause 113 of the *Electricity Safety Act 1998* (**Act**) and the *Electricity Safety Management (Regulations) 1999*. These instruments require that, in order for a DNSP to apply for variations or exemptions from the regulations made under the Act (**Regulations**), the DNSP must have in force an ESMS that has been approved by the Order of the Governor in Council.

On the basis of the ESMS, CitiPower has applied to ESV for a number of exemptions from various Regulations in the form of Electrical Safety Management Plans (**EMSP**). These are detailed in Table 5.11.

[27] The existing Electricity Safety Management Schemes for Powercor and CitiPower were approved by an Order in Council on 26 October 2004.

Exemption Application	Regulation of *Electrical Safety (Network Assets) Regulation 1999*	Commencement – Expiry of exemption
Aerial Service Lines Clearance	13(1)	Approved 15 Jul 05 and expires – refer future arrangements of ESMS
Aerial Substation Ground Clearances	22(3)	Submitted to but not approved by ESV
Clearances of Electricity Supply Network Assets to Tramway Assets	17	Submitted to but not approved by ESV
HV Earth Testing	23(2) and 27(2)	Submitted to but not approved by ESV
Underground Cable - Depths and Mechanical Protection	20(2),(3) and (4)	ESV approved for cables built prior to 31 Dec 1999

Table 5.11: CitiPower's variations and exemptions

CitiPower notes that:

- the existing ESMS is due to expire in October 2009;
- all currently approved (and requested) exemptions relate to the Electricity Safety (Network Assets) Regulations 1999. These Regulations are scheduled to sunset in December 2009 and will not be replaced;
- it is currently not clear whether the exemptions from these Regulations as granted by the ESV will lapse:
  - o at the time the *Electricity Safety (Network Assets) Regulations 1999 sunsets* in December 2009; or
  - o when the existing ESMS expires.

  Alternatively, they may continue to be relevant until CitiPower submits a new ESMS in accordance with the arrangements foreshadowed in the *Electrical Safety Amendment Act 2007* and the *Energy and Resources Legislation Amendment Bill 2009*.

The *Electrical Safety Amendment Act 2007* and the *Energy and Resources Legislation Amendment Bill 2009* set out how the ESV proposes to deal with variations and exemptions from the regulations made under the Act going forward. In particular, it requires that CitiPower[28] must develop a new ESMS that sets out how it will operate and maintain its network in a safe manner. CitiPower's ESMS will need to address those areas which will vary from strict compliance with the new *Electricity Safety (Installations) Regulations 2009* and demonstrate an equivalent level of electrical safety outcome. This means that under the new framework, CitiPower will no longer be required to apply for exemptions from Regulations.

[28] This requirement on CitiPower to prepare an ESMS for ESV's formal approval is by virtue of CitiPower being defined as a Major Electricity Company (MEC) under the *Energy and Resources Legislation Amendment Bill 2009*.

CitiPower has provided as attachments to this Regulatory Proposal copies of:

- the current ESMS for 2004-2009; and
- all existing ESMPs, including those which the ESV has received but not approved.

CitiPower highlights that the ESV has prepared a Regulatory Impact Statement on the new *Electricity Safety (Management) Regulations 2009 which are due to take effect from 1 January 2010.* This RIS states that:

> *'The implementation of the proposed regulations [Electricity Safety (Management) Regulations 2009] is expected to increase the substantive cost to a significant degree. This reflects both the fact that two MCE will be subject to ESMS requirements for the first time and the fact that ESV expects to require more detailed and wider ranging ESMS to be prepared under the new mandatory arrangements than have been adopted in practice under the current voluntary scheme. While no precise quantification of the likely size of the substantive cost increases is possible, and indicative estimate is that the current level of substantive costs could increase by a factor of up to 100 per cent following the implementation of the mandatory ESMS arrangements.'*

CitiPower has not included a capital expenditure allowance for this foreshadowed increase in costs in its Environmental, Safety and Legal capital expenditure forecasts in the next regulatory control period.

In relation to Aerial Service Line Clearance and Underground Cable - Depths and Mechanical Protection, CitiPower is proposing to maintain its current approach and is therefore not seeking any additional capital expenditure in the next regulatory control period. The Environmental, Safety and Legal capital expenditure forecasts is therefore not sensitive to the Aerial Line Service exemption (or the expiry of the exemption).

Compliance audits

Paragraphs 3.7(a)(iv) and 3.7(f)(i)-(iii) of the RIN require CitiPower to provide information about compliance audits that have been undertaken during the previous and current regulatory control periods.

The ESV undertook a selected audit of CitiPower's current ESMS in June 2009. The audit report did not identify any non-compliance against the ESMS, although some minor improvement opportunities were identified.

The *Electricity Safety (Bushfire Mitigation) Regulations 2003* require all DNSPs to submit an annual Bushfire Mitigation Strategy to the ESV, which provides information on bushfire mitigation activities. The Plan must outline a maintenance regime to inspect and repair electricity infrastructure to minimise the risk of distribution assets starting fires.

The ESV annually audits CitiPower against its Bushfire Mitigation Strategy to ensure compliance with the Regulations. The audit is in the form of both a field and a database audit. CitiPower must also submit to the ESV a monthly bushfire mitigation status report and a bushfire performance index.

The ESV undertook an audit and subsequently provided conditional approval of the *2008-09 CitiPower Bushfire Mitigation Strategy*. The reason for the conditional approval related to the inspection interval for private overhead service lines without poles exceeding the prescribed 37 month interval under Regulation 7 of the *Electricity Safety (Bushfire Mitigation) Regulations 2003*. As stated in CitiPower's Bushfire Mitigation Strategies Plan 2009/10, these lines will be inspected as part of a separate program to inspect all points of attachment by December 2009. This will ensure full compliance with the requirements of the *Electricity Safety (Bushfire Mitigation) Regulations 2003* until mid 2011. CitiPower has not incurred any capital expenditure in respect of this program of works and has not included any forecast capital expenditure for inspection of points of attachment in the 2011-15 Environmental, Safety and Legal capital expenditure forecast.

CitiPower is waiting for a response from ESV to its exemption request regarding the continuation of the industry practice of not drill testing treated pine private overhead electric line (**POEL**) poles and not excavating POEL poles located in sealed surfaces.

CitiPower also notes that the ESV conducted a follow up Bushfire Mitigation audit in August 2009 focusing only on the management of steel conductors. At the time of submitting this Regulatory Proposal, the field sampling component is yet to be completed.

Changes to safety obligations

For the purposes of paragraphs 3.7(a)(v) and 3.7(g) of the RIN, CitiPower confirms that there will be new changes to its existing safety obligations arising from changes to the *Victorian Electricity Safety Act 1998 (Act)* and associated Regulations during 2009 and 2010. In particular:

- the Act is currently being amended, although the form of these amendments has not yet been finalised; and
- a number of regulations made under the Act will sunset during 2009. Some of these will be replaced with new Regulations, while others will not.

The *Electrical Safety Amendment Act 2007* and *Energy and Resources Legislation Amendment Bill 2009* foreshadow some changes to these requirements, including the need for Major Electricity Company (**MECs**), including CitiPower, to submit a new ESMS.

Because the details of the amendments have not been finalised at the time of submitting this Regulatory Proposal, CitiPower is not able to provide the information to address paragraph 3.7(g) of the RIN. CitiPower has not included a capital expenditure allowance for this foreshadowed increase in costs in its Environmental, Safety and Legal capital expenditure forecasts in the next regulatory control period.

CitiPower is not aware of any other substantive changes to its Environmental, Safety or Legal obligations or requirements in the forthcoming regulatory control period.

For the purposes of paragraphs 3.7(d)(ii) of the RIN, CitiPower confirms that there have been no changes to regulatory obligations or requirements during the previous (2001-05) regulatory control period, or during the years 2006-08 of the current regulatory control period.

5.7.6 Variances in Environmental, Safety and Legal capital expenditure

Clause S6.1.1(7) of the Rules requires CitiPower to explain significant variations in forecast capital expenditure from historical capital expenditure. In addition, Paragraph 3.7(b)(iii)(1) of the RIN requires CitiPower to explain variances between forecast and actual Environmental, Safety and Legal capital expenditure.

CitiPower estimates that its Environmental, Safety and Legal capital expenditure for the 2006-10 regulatory control period will be $9 million ($2010). It is forecasting that this will increase to $20 million ($2010) in the 2011-15 regulatory control period, which is an increase of approximately 122 per cent.

The main driver of this increase in Environmental, Safety and Legal capital expenditure over the 2011-15 regulatory control period is expenditure on the mitigation of noise at zone substations.

5.7.7 Why the forecast expenditure is justified

CitiPower is committed to managing its distribution system, and delivering electricity to customers, in accordance with high standards of safety and environmental responsibility.

CitiPower's Environmental, Safety and Legal capital expenditure forecast for the next regulatory control period:

- is required in order to satisfy existing regulatory and legislative obligations;
- will deliver safety benefits to customers; and
- will deliver environmental benefits, in particular as a result of the substation bunding program which will reduce environmental cleanup costs and the noise reduction projects at the Brunswick Zone Substation, Northcote Zone Substation, Kew Zone Substation, Flinders / Ramsden Zone Substation and Balaclava Zone Substation.

5.8 SCADA and network control

5.8.1 Expenditure forecast for 2011-2015

Clause S6.1.1(1) of the Rules requires CitiPower to provide a forecast of its SCADA and Network Control capital expenditure for the next regulatory control period. This forecast is detailed in Table 5.12.

	$'000s (real 2010)[1]					
Expenditure category	2011	2012	2013	2014	2015	Total
SCADA and network control	4,575	4,250	4,552	4,700	4,760	22,837

Table 5.12: CitiPower's network control (SCADA) capital expenditure forecasts for 2011-15

5.8.2 Relevant key drivers or inputs and key assumptions

The key drivers or inputs and key assumptions that are relevant to the network control (**SCADA**) capital expenditure forecast are:

- labour cost escalators;
- contracts/other cost escalators;
- material cost escalators;
- forecast inflation;
- unit rates; and
- 2010 indexation.

The nature of these key drivers or inputs and key assumptions is discussed in section 5.2.1 of this Regulatory Proposal.

5.8.3 Nature, aims, objectives and distinguishing features

Paragraphs 3.1(a)(i)-(ii) of the RIN require CitiPower to describe the nature of, and aims and objectives for, its SCADA and Network Control capital expenditure as well as the factors that distinguish it from other categories of capital expenditure.

Supervisory Control and Data Acquisition (**SCADA**) is required to provide 24 hour monitoring and control of CitiPower's zone and sub-transmission substation assets and other distribution network assets (including feeders). CitiPower is therefore committed to ensuring that its SCADA and associated network protection and control equipment meets good industry practices.

In the current regulatory control period, CitiPower started updating its existing protection and control communications infrastructure and will continue to rollout these changes over the next regulatory control period. CitiPower is also committed to undertaking new investment in the 2011-15 regulatory control period in order to improve its knowledge of network performance, improve data security, increase data visibility and provide more accurate and timely information to customers on fault rectification.

In this way, CitiPower's SCADA and Network Control capital expenditure forecasts represent what it considers is necessary, for the purposes of clause 6.5.7(a) of the Rules, in order to:

- meet and manage the expected demand for network services over the 2011-15 regulatory control period; and
- ensure that its distribution system, and its network services, meet relevant quality, reliability, safety and security of supply standards.

For the purposes of paragraph 3.1(a)(ii) of the RIN, CitiPower does not consider that there is any reasonable scope for ambiguity between SCADA and Network Control capital expenditure, and any other expenditure category.

5.8.4 Methodology

Paragraph 3.1(c)(iii) of the RIN, and clause S6.1.1(2) of the Rules, require CitiPower to explain the methodology by which it has prepared its SCADA and Network Control capital expenditure forecasts. In addition, paragraphs 3.2(a) and 3.1(c)(iv) of the RIN require CitiPower to provide information about documents that it has used in preparing its forecasts.

The 2011-15 capital expenditure program for SCADA and related communications equipment includes provision for the:

- continuation of the installation of new protection and control communications infrastructure;
- installation of Distribution Management System (DMS) field devices; and
- increased substation monitoring and automation investments.

Each of these projects is discussed in turn below.

The methodology for determining required expenditure for each of these projects in the next regulatory control period is discussed in turn below. Taken together, these projects constitute the total SCADA and Network Control capital expenditure forecast for the 2011-15 regulatory control period.

For the purposes of paragraph 3.8(b) of the RIN, CitiPower observes that it did not undertake any cost benchmarking for the SCADA and Network Control capital expenditure forecasts.

Continued installation of new protection and control communications infrastructure

Currently, the protection and control systems in CitiPower's zone substations are based on a range of technologies, including supervisory cable systems[29] and Permitted Attached Private Lines (**PAPL**). In both cases, information is transmitted to the

[29] This copper supervisory system links zone substations to each other predominately for zone substation control and monitoring and protection purposes. This is a mix of overhead and underground cables, where monitoring systems in CitiPower's distribution indoor substations use a separate underground CBD supervisory cable system. This underground CBD copper supervisory system emanates out of separate zone substations that act as hubs – it does not connect zone substations and is used for remote monitoring of distribution indoor substations only.

control room via Voice Frequency (**VF**) technology. Protection systems between the zone substations also use this supervisory cable system.

Monitoring systems in CitiPower's distribution indoor substations use a separate underground CBD supervisory cable system.

During the current regulatory control period, CitiPower commenced migrating away from supervisory cable and PAPL systems and the associated infrastructure. This is because:

- PAPL systems will cease being available from 2010, as Telstra is withdrawing PAPL from its service offering. This is because PAPL systems are outdated and provide limited service capability. The associated Voice Frequency (**VF**) technology and equipment (carrier technology) is also outdated and approaching obsolescence; and

- standard protection relay equipment now comes with fibre interfaces. This means that the supervisory cable system used for protection purposes will become redundant as CitiPower moves to upgrade protection relays. Further, due to the large distances between zone substations, Ethernet equipment operating over copper networks loose speed to a point where they become unworkable and are not suitable for communication (**SCADA**) services. This means that the supervisory cable system will become redundant.

In the future, CitiPower's protection and control systems (Zone Substation) will be upgraded and will predominately utilise fibre based systems which CitiPower has commenced constructing in the CBD. Currently the fibre is used to enable protection schemes between zone substations in the CBD and inner urban area as well as remote monitoring where equipment has been upgraded to Ethernet based protocols. CitiPower has commenced installing Ethernet switches and associated infrastructure on the existing fibre based systems to allow the provision of Ethernet activities. This infrastructure will continue to be deployed in the next regulatory control period.

Ethernet is a standard technology that allows high speed communications for data and information transfer required for control and monitoring services. It will enable the communication of data between zone substations and control centres, as well as intra-zone substation connectivity. The deployment of Ethernet will also enable the uptake of new capability, including:

- condition monitoring of older plant;
- fault downloads at head office for rapid analysis;
- improved security of SCADA control and data;
- improved network access for onsite field staff;
- voice over internet protocol (VoIP) phones; and
- cameras and security systems across critical infrastructure.

Figure 5-5 shows the current zone substation monitoring and control infrastructure and equipment. Figure 5-6 shows what CitiPower intends the zone substation monitoring and control infrastructure will comprise by the end of the next regulatory control period.

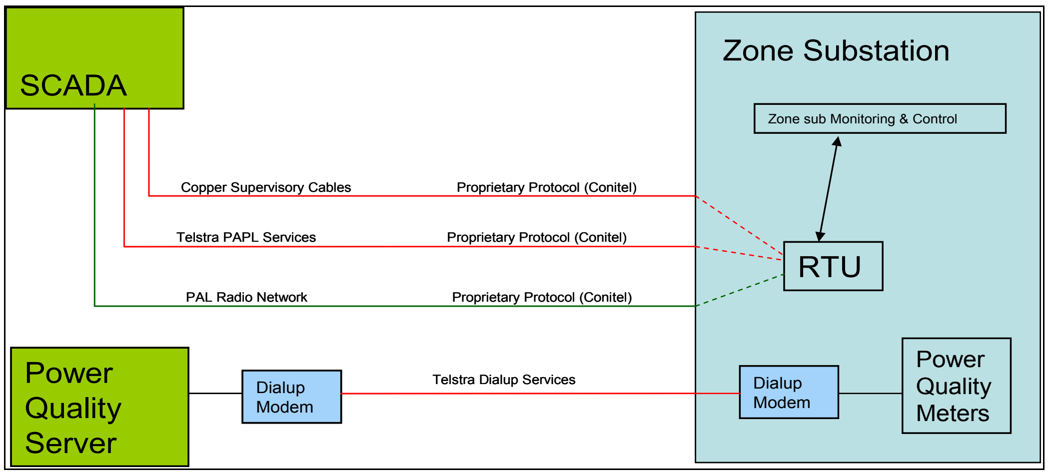

Figure 5-5: Current zone substation monitoring and control infrastructure and equipment

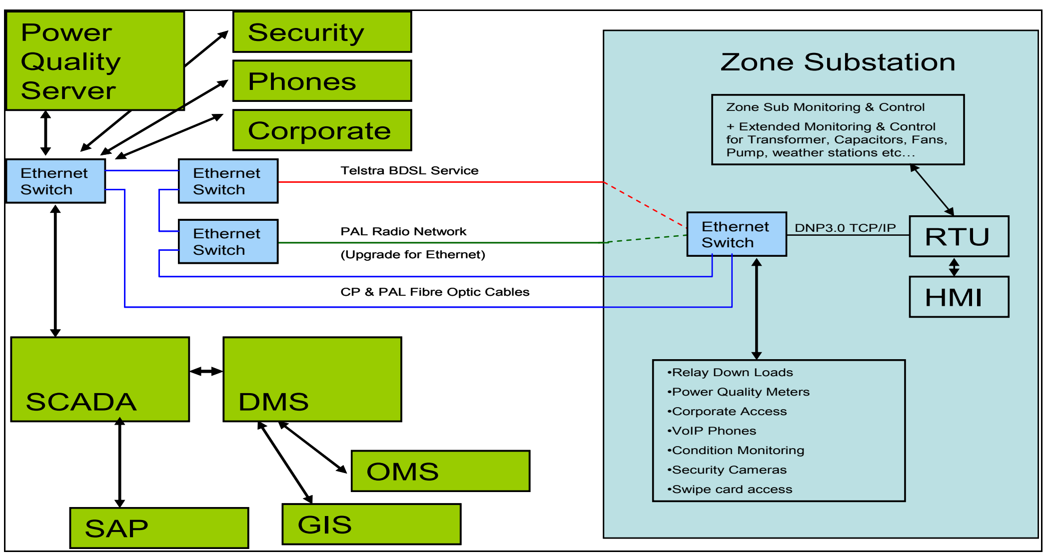

Figure 5-6: Zone substation monitoring and control infrastructure and equipment as at 2015

CitiPower has started installing new protection and control communications infrastructure in the current regulatory control period. The forecast expenditure required to install the new infrastructure is based on the program costs that CitiPower has incurred in the current regulatory control period.

Distribution Management System (DMS) field devices

The DMS is part of CitiPower's information technology system and is designed to support and extend CitiPower's SCADA operations. DMS will enable, amongst other things, integration of the existing SCADA technology with the existing Geographic Information System (**GIS**)[30].

Importantly, the DMS is:

- not part of the distribution network. Rather, it is part of CitiPower's IT assets. Accordingly it is included in the IT capital expenditure forecast and is discussed in detail in Chapter 28 of this Regulatory Proposal; and
- further supported by network field assets, which transmit field data to it. These assets include, switches and fault indicators. These assets are located in the distribution network (as opposed to the control room) and remotely feed information back to the DMS. This information assists DMS in planning, control, and fault management functions. The network field assets which support DMS are included in the SCADA expenditure forecast.

CitiPower will commence installing DMS field devices once the DMS project is completed (expected to be end of 2011). The forecast expenditure associated with this program of works is based on current knowledge of the costs of DMS field devices and the expected volume of devices.

Increased substation monitoring and automation and security monitoring investments

Over the 2011-15 regulatory control period, CitiPower will continue existing programs, or commence new programs, in order to extend coverage of the SCADA and associated monitoring and control equipment, so as to gain greater visibility of its network. In particular, CitiPower will, amongst other things:

- commence a program of installing remote fault indicators on poles in order to detect faults and to enable information to be fed back remotely to the control rooms;
- continue its program to enhance zone substation monitoring. This involves implementing remote control devices that will enable CitiPower to better control and monitor zone substation equipment including transformers, capacitor banks, fans and pumps. For the first time, CitiPower will then be able to monitor and control all this equipment remotely; and
- commence installing security cameras at zone substations. This will enable CitiPower to remotely monitor any activity at its zone substations in order to deter vandalism and theft.

The forecast expenditure associated with this program of works is based on current estimates for the installation of this type of equipment.

[30] Currently SCADA and GIS operate separately of each other.

5.8.5 Other information

Paragraph 3.8 of the RIN requires CitiPower to provide certain other information in relation to its SCADA and network control capital expenditure.

SCADA and Network Control capital expenditure in the current regulatory control period

Paragraph 3.8(a) of the RIN requires CitiPower to provide information in relation to its capital expenditure on SCADA and Network Control in the current and next regulatory control periods.

CitiPower is seeking to include an allowance of around $24 million in its capital expenditure building block for the next regulatory control period. As discussed in section 5.8.4 above, this allowance relates to the:

- installation of new protection and control communications infrastructure;
- installation of DMS field devices; and
- increased substation monitoring and automation investments.

Each of these initiatives has been started in the current regulatory control period, except the installation of DMS field devices.

Table 5.13 provides further information about projects accepted by the ESCV for the 2006-10 regulatory control period that have been included in the capital expenditure forecast for the 2011-15 regulatory control period.

Projects proposed by CitiPower	Projects accepted by ESCV for 2006-10 regulatory control period (Paragraph 3.8(a)(ii) of the RIN)	Project status in 2006-10 regulatory control period (Paragraph 3.8(a)(iii) of the RIN)	Rationale for inclusion in capital expenditure forecast for next regulatory control period
Replacement of aged communications equipment	No- Refer to section 5.10 of the Regulatory Proposal.	CitiPower commenced undertaking this activity during the current regulatory control period. This activity relates to migrating the supervisory cable system used for monitoring and protection of zone substations to fibre based systems.	This activity forms part of the installation of new protection and control communications infrastructure project, which is discussed in section 5.8.4 above.

Projects proposed by CitiPower	Projects accepted by ESCV for 2006-10 regulatory control period (Paragraph 3.8(a)(ii) of the RIN)	Project status in 2006-10 regulatory control period (Paragraph 3.8(a)(iii) of the RIN)	Rationale for inclusion in capital expenditure forecast for next regulatory control period
Upgrading zone substation monitoring and control systems	No- Refer to section 5.10 of the Regulatory Proposal.	CitiPower commenced undertaking this activity during the current regulatory control period. This activity relates to enhancing the functionality of zone substations by implementing remote control devices that enable it to remotely control and monitor equipment within the zone substation, including transformers, capacitor banks, fans and pumps.	This activity forms part of the increased substation monitoring and automation investments, which is discussed in section 5.8.4 above. CitiPower plans to continue to enhance the functionality of around four zone substations per year over the 2011-2015 regulatory control period.
Additional SCADA data security and security monitoring	No- Refer to section 5.10 of the Regulatory Proposal.	CitiPower commenced undertaking this activity during the current regulatory control period. This activity relates to improving system security through installing devices such as smart entry systems at zone substations.	This activity forms part of the increased substation monitoring and automation investments, which is discussed in section 5.8.4 above. CitiPower plans to continue installing security infrastructure, including cameras at zone substations. This will enable CitiPower to remotely monitor its zone substations and act as a deterrent to vandalism and theft.
Replacement of aged remote fault monitoring units	This expenditure forms part of reliability and quality maintained capital expenditure.		

Table 5.13: SCADA projects for current and next regulatory control periods

5.8.6 Why the forecast expenditure is justified

CitiPower is committed to achieving best practice in relation to the protection and control of its network. Continuing to invest in its SCADA and Network Control will enable CitiPower to:

- provide better customer service through greater access to, and security of, data about is distribution system;
- improve the safe management of faults;
- gain greater visibility of network power quality through improved monitoring programs;
- improve network planning through greater knowledge and security of data;
- improve system security through increased remote monitoring devices such as security cameras; and
- improve internal processes utilising better load data including for more accurate distribution asset reporting.

CitiPower's SCADA and Network Control capital expenditure forecasts therefore enable it to:

- meet and manage the expected demand for network services over the 2011-15 regulatory control period; and
- ensure that its distribution system, and its network services, meet relevant quality, reliability, safety and security of supply standards.

5.8.7 Variances in SCADA and Network Control capital expenditure

Clause S6.1.1(7) of the Rules requires CitiPower to explain significant variations in forecast capital expenditure from historical capital expenditure.

CitiPower estimates that its SCADA and Network Control capital expenditure for the 2006-10 regulatory control period will be $6 million ($2010). It is forecasting that this will increase to $23 million ($2010) in the 2011-15 regulatory control period, which is an increase of approximately 283 per cent.

The main factors driving this increase in SCADA and Network Control capital expenditure are:

- continued installation of new protection and control communications infrastructure;
- installation of DMS field devices; and
- increased substation security monitoring investments.

5.9 Non-Network

5.9.1 Expenditure forecast for 2011-15

Clause S6.1.1(1) of the Rules requires CitiPower to provide a forecast of its Non-Network capital expenditure for the next regulatory control period. This forecast is detailed in Table 5.14.

	$'000s (real 2010)[1]					
Expenditure category	2011	2012	2013	2014	2015	Total
Non-Network Assets – IT	9,603	8,681	9,455	13,690	10,779	52,208
Non-Network Assets – Other	3,196	3,695	3,345	3,453	3,516	17,205
Non-Network Assets – Total	12,799	12,376	12,800	17,143	14,295	69,413

Table 5.14: CitiPower's non-network assets capital expenditure forecasts for 2011-15

5.9.2 Relevant key drivers or inputs and key assumptions

The key drivers or inputs and key assumptions that are relevant to the non-network capital expenditure forecast are:

- labour cost escalators;
- contracts/other cost escalators;
- material cost escalators;
- forecast inflation;
- unit rates; and
- 2010 indexation.

The nature of these key drivers or inputs and key assumptions is discussed in section 5.2.1 of this Regulatory Proposal.

5.9.3 Nature, aims, objectives and distinguishing features

Paragraphs 3.1(a)(i)-(ii) of the RIN require CitiPower to describe the nature of, and aims and objectives for, its Non-Network Assets – IT, and Non-Network Assets – Other, capital expenditure as well as the factors that distinguish it from other categories of capital expenditure.

While this capital expenditure does not directly relate to the distribution system, it is essential to ensuring that CitiPower's distribution system, and its distribution services, meet relevant quality, reliability, safety and security of supply standards.

For the purposes of paragraph 3.1(a)(ii) of the RIN, CitiPower does not consider that there is any reasonable scope for ambiguity between Non-Network Assets – IT, and Non-Network Assets – Other, capital expenditure and any other expenditure category.

For the purposes of paragraph 3.8(b) of the RIN, CitiPower observes that it did not undertake any cost benchmarking for its Non-Network Asset capital expenditure forecasts.

Information technology capital expenditure

CitiPower's information technology (**IT**) can be categorised as follows:

- distribution systems – CitiPower's distribution network is reliant on IT systems for its safe and efficient operation. This includes supporting the management of distribution assets, including:

    - controlling the network;
    - managing and maintaining assets; and
    - responding to faults.

    A large portion of the expenditure on distribution system IT over the next regulatory control period will relate to leveraging the functionality developed as part of the Advanced Metering Infrastructure (**AMI**) project;

- customer service systems – these systems support the provision of distribution services and information for. A large portion of the expenditure on customer service systems over the next regulatory control period will involve replacing the Customer Information System (**CIS**);

- corporate - the corporate systems support financial, payroll, knowledge management and collaboration. A large share of expenditure on corporate systems over the next regulatory control period will involve upgrading the PABX telephone system; and

- IT infrastructure – this refers to the underlying IT support architecture and network, hardware and systems that are used to deliver business functionality.

Other Non-Network capital expenditure

CitiPower's other Non-Network Asset capital expenditure can be categorised as follows:

- general equipment – this relates to miscellaneous tools and equipment that are used in providing distribution services. CitiPower's policy is to capitalise tools and equipment with a value of more than $500 per item;

- motor vehicles – this relates to the purchase, replacement or rebuild costs associated with CitiPower's significant commercial and heavy fleet of vehicles;

- office furniture – this relates to the equipment and furniture that is necessary to service the offices and depots across CitiPower's distribution area, including items such as desks, chairs, whiteboards, televisions, shredders, compactus units and other storage facilities; and

- property – this relates to the provision of office and depot accommodation, buildings and property in line with CitiPower's operational and occupational health and safety requirements. Expenditure on substation property and line easements is not included in this category. Rather, it is incorporated in Reinforcement capital expenditure and Reliability and Quality Maintained capital expenditure.

5.9.4 Methodology

Paragraph 3.1(c)(iii) of the RIN, and clause S6.1.1(2) of the Rules, require CitiPower to explain the methodology by which it has prepared its Non-Network Asset capital expenditure forecasts. In addition, paragraphs 3.2(a) and 3.1(c)(iv) of the RIN require CitiPower to provide information about documents that it has used in preparing its forecasts.

Information technology capital expenditure

CitiPower's IT capital expenditure over the next regulatory control period is based on its IT Strategic Plan. The IT Strategic Plan has been developed following internal consultation within CitiPower and has been endorsed by CitiPower's Capital Investment Committee. A copy of the IT Strategic Plan has been provided as an attachment to this Regulatory Proposal.

The IT Strategic Plan has also been independently reviewed by Gartner Inc (**Gartner**), which is one of the world's leading information technology research and advisory companies. Gartner found the Plan represented *'best practice'* and the proposed initiatives were assessed to align to key business needs and priorities. A copy of Gartner's report entitled *Review of Powercor/CitiPower IT Strategy* has been provided to the AER as an attachment to this Regulatory Proposal (see Attachment C0012).

CitiPower's high level IT project estimation process involves six key steps, although the level of complexity of each step may vary depending on the complexity of the project, the amount of information that is available and the period of time that it is being assessed in advance of implementation.

Six steps involve:

- I*dentifying the need for the project* – the first step is to identify the need for the project, which will be typically identified from either an initiative, issue or business strategy from either the IT unit or other business units. Initially this may just be a concept or a required outcome and may contain limited detail;

- *Validate and clarify* – this step involves working with the initiative owner to further clarify details of the requirement, helping identify high level customer and business benefits to a level of detail appropriate for the scope of the estimate;

- *Identify options* – this step involves identifying the most suitable system and application area for the initiative. The IT application owner will then review the requirement and assess the best approach; this could include an update or change request to an existing system, purchase of new complementary software, in house development or replacement of existing software and/or hardware. This approach will be based on previous project experience and will align to the IT strategy and IT policies;

- *Preliminary costing* - this step involves generating IT estimates using an individual project approach. A high level cost will then be established this will include:

  - hardware costs, all new hardware and upgrades to existing hardware, maintenance of performance and security of systems;

  - software, packaged and in house developed, it will include new, upgrades and increases in licensing, costs for this will be based on known materials, and known user numbers;

  - external labour[31];

  - IT internal labour[32]; and

  - ongoing IT operational costs will also be considered and costed.

  The estimate will be created using current day dollars and will be based on previous IT projects and the experience of the application manager. Closer to the implementation of the project, indicative quotes may be requested from vendors for validation against internal estimates.

  The volume is determined on a project specific basis. For example, if the project involves an upgrade of the infrastructure system which allows for an increase in transactional loads, the volume is based on the number of customers and the frequency of meter reads. If the project involves an upgrade of a computer system, the volume is based on the number of computers, users and licences.

- *Socialise*– this step involves circulating the cost estimate to the IT management team, the General Manager IT and the business unit, as appropriate, for review and initial approval of:

  - the high level business requirement;

  - the cost estimate; and

  - the proposed year for implementation and the estimated time to complete.

[31] External contractor rates are based on current industry rates and are system/application and contracting company specific. The Hays salary survey and guide http://www.hays.com.au/salary/default.aspx can be used as a source of information along with current rates paid to existing and previous contracts and agency personnel.

[32] IT hourly labour rates are established using an average of IT salary charges, for 2009/10 this is $80 per hour.

If the estimate does not meet requirements it will be returned to the application manager for further clarification and development or alternatively the estimation will not proceed.

- *Detailed estimations, quotation and approval* – this step involves undertaking detailed estimations and obtaining quotations. This may take weeks, months or years depending on Business requirements and the urgency of those requirements. Processes for gaining approval for the final estimation and ultimately for the Project will be done in accordance with financial guidelines, IT Project Management methodology and CIC processes. Refer to Attachment C0013, Governance Framework which provides a description of the investment evaluation process[33].

During the current regulatory control period, significant IT resources were necessarily diverted to system development for the rollout of AMI. This has resulted in an unsustainably low baseline expenditure during the current regulatory control period. AMI system development is expected to begin to decline from early 2010, which will enable CitiPower to focus its efforts over the next regulatory control period on implementing new and upgraded IT systems associated with Standard Control Services.

Key factors that influence the IT capital expenditure forecast by CitiPower for the next regulatory control period include:

- leveraging off the AMI project;
- a major Customer Information System replacement; and
- an increase in the use of mobile computing in the field.

The key capital expenditure initiatives for each of CitiPower's IT categories are detailed in Chapter 28 of this Regulatory Proposal.

Other Non-System Asset capital expenditure

CitiPower's other Non-System Asset capital expenditure has been developed on the following basis.

General equipment

CitiPower has forecast the capital expenditure required on general equipment in the next regulatory control period based on its 2009 expenditure, as this is considered to be an appropriate base year.

Motor vehicles

[33] The Governance Framework describes the investment evaluation process for the current and future regulatory control periods; no change to this has occurred in the current regulatory control period.

CitiPower keeps the number of motor vehicles and mobile plant in its fleet at optimal levels, consistent with business cost, customer service objectives and operational utilisation.

For the purposes of paragraph 3.8I of the RIN, CitiPower confirms that it purchases, rather than leases, motor vehicles. Table 5.15 outlines CitiPower's motor vehicle replacement policy, which is drawn from its *Transport Policy Manual*.

Vehicle	Replacement cycle
Executive Vehicles	4 years or 100,000 kilometres
Sedans, Station Wagons and Utilities	4 years or 120,000 kilometres
Vans	6 years or 140,000 kilometres
Four Wheel Drive-Four Cylinder	6 years or 150,000 kilometres
Four Wheel Drive – Six Cylinder	6 years or 200,000 kilometres
Line construction trucks GLTs	8 years or 250,000 kilometres
Line construction trucks MCTs	10 years or 300,000 kilometres
Speciality Vehicles such as Task Trucks	15 years or 300,000 kilometres
Speciality Vehicles such as Crane Borers	10 years or 300,000 kilometres, replace cab chasses, complete replacement after 20 years
Speciality Vehicles Elevating Platforms	10 year rebuild to AS2550.10, complete replacement at fifteen years
Fork Lifts	10 years
Trailers	15 years
Speciality Plant, Self Loading trailers, cable recovery units.	20 years

Table 5.15: Replacement cycle for motor vehicles

CitiPower has provided a copy of its *Transport Policy Manual* to the AER (see Attachment C0027). This policy applied, and will continue to apply, in the current and next regulatory control periods.

A request for replacement of heavy vehicles and mobile plant with a value of $250,000 must be accompanied by a detailed business evaluation. The purchase of heavy vehicles and plant is generally obtained by a public tender or quote and if over $300,000 be subject to the Governance process outlined in Attachment C0013.

CitiPower has developed its motor vehicle capital expenditure forecasts for the next regulatory control period on the following basis:

- it has applied the above replacement provisions from the *Transport Policy Manual* to the current motor vehicle fleet. This reflects a combination of legislative requirements, manufacturers' recommendations, improvements in occupational health and safety practices and industry best practice standards; and

- it has forecast the acquisition of new fleet associated with forecast construction and maintenance activities.

Office furniture

CitiPower has forecast the capital expenditure required on general equipment and office furniture in the next regulatory control period based on the average actual expenditure from the previous four years.

Property

CitiPower has forecast the capital expenditure required on property in the next regulatory control period based on a list of identified projects for 2010. The 2010 expenditure for these projects has been adopted as the benchmark for the next regulatory control period. These key projects include:

- increased pole storage areas at a forecast cost of $140,000 over the next regulatory control period;
- fire service underground pipe replacement projects, due to leaks, at a cost of $60,000 over the next regulatory control period; and
- security fence replacements and upgrades at a cost of $45,000 over the next regulatory control period.

5.9.5 Other information

Paragraph 3.8(a) of the RIN requires CitiPower to provide information in relation to its capital expenditure on Non-Network Assets in the current and next regulatory control periods.

The ESCV notionally included an allowance of $43 million ($ 2004) for Non-network assets – IT, including an upgrade of CitiPower's CIS in the capital expenditure building block for the current regulatory control period[34]. As noted above, it was originally envisaged that the CIS would be replaced around 2009. However, the introduction of AMI resulted in the project being deferred on the basis that changing billing systems could potentially increase the risks of delivering the AMI project. CitiPower now intends implementing a new CIS in 2014-15.

The remainder of CitiPower's Non-Network Assets capital expenditure was not covered in the ESCV's 2005 Price Determination.

5.9.6 Why the forecast expenditure is justified

CitiPower needs to incur capital expenditure on IT, general equipment, motor vehicles, office furniture and property in order to support the delivery of its distribution services. While this capital expenditure does not directly relate to the distribution system, it is

[34] Note that the ESCV provided a total capital expenditure allowance based on a top down assessment. It did not provide specific allowances for individual capital expenditure categories or projects.

essential to ensuring that CitiPower's distribution system, and its distribution services, meet relevant quality, reliability, safety and security of supply standards.

The nature and explanation of each material project relevant to non-network capital expenditure are detailed in Chapter 28.

5.9.7 Variances in Non-Network Asset capital expenditure

Clause S6.1.1(7) of the Rules requires CitiPower to explain significant variations in forecast capital expenditure from historical capital expenditure.

CitiPower estimates that its Non-Network Asset capital expenditure for the 2006-10 regulatory control period will be $35 million ($2010). It is forecasting that this will increase to $69 million ($2010) in the 2011-15 regulatory control period, which is an increase of approximately 97 per cent.

The main factors driving this increase in Non-Network Asset capital expenditure are outlined below.

Main factors driving increase in Non-Network Asset – IT capital expenditure

The significant IT resources that were diverted to preparing system readiness for the rollout of AMI resulted in an unsustainably low baseline expenditure during the current regulatory control period. AMI system development is expected to begin to decline from early 2010, which will enable CitiPower to focus its efforts over the next regulatory control period on implementing new and upgraded IT systems associated with Standard Control Services.

Going forward, the main factors driving CitiPower's increased IT capital expenditure are:

- increases in baseline costs – this increase is required in order to support the existing suite of IT applications; and
- new applications and systems – this increase in costs is associated with extending and replacing the existing suite of applications to meet the increasing business requirements.

The key factors that influence the IT capital expenditure forecast by CitiPower for the next regulatory control period are:

- increasing levels of new personnel and contractors, using CitiPower's IT systems. This has, and will continue, to result in higher expectations of systems reliability and IT support;
- higher standards of governance, complexity of information, requirements to respond more quickly which require greater levels of IT system security, performance and capability;
- an increase in the use of mobile computing in the field;

- a major Customer Information System replacement; and
- leveraging off the AMI project.

Main factors driving increase in Non-Network Assets – other capital expenditure

The main factors driving CitiPower's Non-Network Assets other capital expenditure is the continued business as usual expenditure requirements.

This requires, amongst other things, a major inspection of cranes to be carried out after ten years and five years thereafter and recommends upgrading units to the latest safety features and devices (ie load and slew indicators). A comprehensive catch-up program has been developed to address those units now falling due, which has resulted in additional capital expenditure to ensure CitiPower's plant is compliant with AS 2550.5.

5.10 Historical variances in capital expenditure

Capital expenditure for the previous and current regulatory control period is set out in Regulatory Template 2.1, as required by the RIN and clause S6.1.1(6) of the Rule.

Clause S6.1.1(7) of the Rules requires CitiPower to explain any significant variations between forecast and historic capital expenditure. The variations between capital expenditure for 2011-15 and 2006-10 are explained for each expenditure category in sections 5.4 and 5.9 of this Regulatory Proposal.

The variations between capital expenditure for 2006-10 and 2001-05 are discussed in the ESCV's 2006-10 EDPR. In particular, the ESCV states that it:

> *'recognises that there are reasons as to why a reasonable forecast of capital expenditure for 2006-10 may be different from historic* [2001-05] *expenditure including:*
>
> - *growth in peak demand;*
> - *the ageing of the asset base – which may lead to an increase in expenditure;*
> - *the removal of expenditure for reliability improvements from the forecasts; and*
> - *expenditure to comply with the new regulatory obligations such as amendments to the Electricity Safety Regulations.'*[35]

Paragraph 3.10 of the RIN requires CitiPower to provide information in relation to variations detailed in Regulatory Template 5.1 between its *'historical capex'* and the capital expenditure building blocks that were approved by the ESCV in its 2005 Price Determination.

[35] ESCV, 2006-10 EDPR, page 269

The term *'historical capex'*, while italicised where it appears in paragraph 3.10, is not defined in the RIN. Having regard to the fact that Regulatory Template 5.1 seeks information on variations between actual and ESCV forecast capital expenditure for each year of the current regulatory control period, CitiPower has interpreted the term *'historical capex'*, where it appears in paragraph 3.10 of the RIN, as meaning CitiPower's capital expenditure in the current regulatory control period.

Consideration of CitiPower's capital expenditure for the current regulatory control period by reference to the benchmarks established by the ESCV requires careful analysis of the basis on which the ESCV benchmarks were set.

The ESCV determined in the 2006-10 EDPR (at p.270) to forecast gross capital expenditure at the aggregate level for the current regulatory control period. The ESCV:

> *'decided that a reasonable forecast of gross capital expenditure at the aggregate level for each distributor over the 2006-10 regulatory period is an amount that is 30 per cent greater than the historic expenditure incurred by that distributor over the 2001-04 period.'*

Thus, as noted by the ESCV on page 272 of the 2005 Price Determination, it:

> *determined the distributor's capital expenditure requirements for 2006-10 at an aggregate level rather than an asset category level.*

While the ESCV calculated a forecast of capital expenditure by asset (or expenditure purpose) category, which forecasts appear in the completed Regulatory Template 5.1, as the ESCV observes in the 2005 Price Determination (at p.272), these forecasts of capital expenditure were:

> *'determined by prorating the difference between the Final Decision at an aggregate level and the expenditure cap across asset categories.'*

The *'expenditure caps'* were an outcome of the ESCV's review of the distributors' capital expenditure proposals by asset category (determined by the ESCV by making a series of adjustments to those distributor proposals) and their only purpose contemplated by the ESCV (at p.273) was to *'provide a limit on the additional capital expenditure above that included in the revenue requirement for which the financing costs may be rolled into the regulatory asset base in 2011'*. Significantly, the ESCV did not intend that the forecast capital expenditure by asset category would support a meaningful comparison between those forecasts and the capital expenditure incurred by the distributors in the current regulatory control period.

Accordingly, while the ESCV's approach to determining forecast capital expenditure by asset category was adequate for the ESCV's intended purposes, it did not produce forecasts of capital expenditure by asset category that provide a robust and reliable basis of comparison with distributors' capital expenditure by asset category (as per Regulatory Template 5.1) in the current regulatory control period. Notably, the ESCV recognised that even its forecast gross capital expenditure at the aggregate level for the current regulatory control period may not reflect a distributor's capital expenditure requirements for the period. The ESCV relevantly stated (at p.271) in respect of its methodology of forecasting capital expenditure at the aggregate level by grossing up historical expenditure by 30 per cent that:

> *'[T]he Commission recognises that this approach is subject to some risk in that it is conceivable that a distributor's capital expenditure requirements during the 2006-10 period might exceed the forecast capital expenditure'.*

In summary, there was no bottom up construction by the ESCV of capital expenditure benchmarks by asset category detailed in Regulatory Template 5.1 and the ESCV's approach to determining forecast capital expenditure by asset category did not produce forecasts that support a robust and reliable comparison with distributors' capital expenditure by asset category (as per Regulatory Template 5.1) in the current regulatory control period.

CitiPower has therefore sought to examine and explain variations at an aggregate, as opposed to expenditure purpose, level, consistent with the approach that was taken by the ESCV to set the benchmarks in the 2006-10 EDPR.

Table 5.16 compares CitiPower's actual and estimated capital expenditure for the current regulatory control period with the ESCV's regulatory allowance for the current regulatory control period.

	$'000s (real 2010)					
Capital Expenditure	2006	2007	2008	2009	2010	Total
Actual	102,306	94,326	115,798	129,480	140,515	582,425
Regulatory allowance	120,186	114,715	113,054	124,105	105,224	577,284
Difference	(17,880)	(20,389)	2,744	5,375	35,291	5,141

Table 5.16: Capital expenditure over 2006-10

CitiPower's network is unique compared to other Australian electricity networks. It is the smallest in Australia whilst having the highest load density. These factors result in CitiPower's capital expenditure being characterised by relatively few, but very large high capacity network extensions and connections. As a consequence CitiPower's capital expenditure profile cannot be characterised by a smooth trend, but rather as a series of sporadic lumpy expenditure, whereby the inclusion or deletion of one large project will significantly alter the capital expenditure trend.

At an aggregate level, CitiPower's historical capital expenditure is below the aggregate benchmark in the years 2006 and 2007. The variance almost exclusively relates to reinforcement expenditure and in particular the deferral of the Metro 2012 project, which is detailed in section 5.4.5 of this Regulatory Proposal.

The deferral of the Metro 2012 project was due to the significant synergies that exist between it and the CBD Security of Supply project. The costs of undertaking each of these projects on a standalone basis, rather than together, would have been significantly greater and would not have been in the long term interests of CitiPower's customers. As such, CitiPower was committed to ensuring these projects were undertaken together.

However unlike the Metro 2012 project, the CBD Security of Supply project was not approved as part of the ESCV's Final Decision for the current regulatory control period and was required to be subject to further consultation. This additional consultation process took a further three years, with the ESCV finally approving CitiPower's CBD Security of Supply Upgrade Plan on 18 August 2008. As a result, the large expenditure expected over the current regulatory control period has not materialised.

The Metro 2012 project and the CBD Security of Supply project will now form part of CitiPower's capital expenditure program at the end of the current regulatory control period and will continue into the next regulatory control period.

For the purposes of paragraph 3.10(a)(i) of the RIN, CitiPower therefore observes that the reasons for any variations between the ESCV's decision on capital expenditure by asset (or expenditure purpose) category and CitiPower's capital expenditure for the relevant expenditure purpose category in the current regulatory control period identified in the completed Regulatory Template 5.1 are as follows:

- variations in respect of all expenditure purpose categories result, in whole or in part, from the fact that the ESCV did not prepare its forecasts of CitiPower's capital expenditure by asset category on the basis of a bottom up build and, thus, never provided a reliable estimate of CitiPower's capital expenditure requirements by expenditure purpose category for the current regulatory control period; and

- variations in respect of the reinforcements expenditure purpose category result, in part, from the deferral of the Metro 2012 project.

In response to paragraph 3.10(a)(ii) of the RIN, it has been noted that CitiPower's capital expenditure is not characterised by a smooth trend but rather by a sporadic lumpy expenditure profile. As a result, trends cannot be readily drawn from historical capital expenditure that would facilitate a review of recurrent and current items.

In response to paragraph 3.10(a)(iii) of the RIN, the factors which generally influenced variations to the ESC approved allowance have been discussed in response to paragraph 3.10(a)(i) of the RIN, above. The variations between the ESV forecast and actual spend was predominantly driven by a large and lumpy project namely, the Metro 2012 project, and the methodology adopted by the ESCV to determine its allowances.

Paragraph 3.10(b) of the RIN, requires CitiPower to provide documents, which relate to externally imposed variations, where a variation is due to factors beyond CitiPower's control.

The decision to defer the Metro 2012 project was made internally by CitiPower's management team. However, the variations are due to factors beyond CitiPower's control to the extent that the variations between actual capital expenditure and the ESCV's allowance in the current regulatory control period are due to the methodology adopted by the ESCV to determine its allowances and the resultant fact that these never provided (and were never intended by the ESCV to provide) a reliable estimate of CitiPower's capital expenditure requirements by expenditure purpose category for the current regulatory control period.

Accordingly, for the purposes of paragraph 3.10(b) of the RIN, CitiPower only refers the AER to the ESCV's 2005 Price Determination (which CitiPower understands is already in the AER's possession, with the result that there is no need for CitiPower to annex it to this Regulatory Proposal).

6. OPERATING EXPENDITURE

This Chapter details CitiPower's forecast operating expenditure for Standard Control Services for the next regulatory control period and addresses specific requirements of the Rules and the RIN.

6.1 Operating expenditure forecast for 2011-15

Clause 6.4.3(a)(7) of the Rules provides that operating expenditure is one of the building blocks to be used in calculating the Annual Revenue Requirement for Standard Control Services. Clause 6.4.3(b)(7) of the Rules requires this forecast to be determined in accordance with clause 6.5.6 of the Rules.

CitiPower's operating expenditure forecasts for each year of the 2011-15 regulatory control period that are required to meet the requirements of clause 6.5.6 of the Rules are as follows:

	$'000 (2010)					
	2011	2012	2013	2014	2015	Total
Base operating expenditure	36,168	36,168	36,168	36,168	36,168	180,840
Non-recurrent operating expenditure	-	-	-	-	-	-
Reassignment of overhead costs due to increase in capital costs	(2,772)	(2,955)	(2,775)	(2,507)	(2,444)	(13,453)
Step change due to changes in service classification	(1,514)	(1,514)	(1,514)	(1,514)	(1,514)	(7,570)
Step changes related to changes in scope	5,787	5,653	6,424	2,906	3,262	24,032
Network growth scale escalator	1,344	2,318	3,374	4,437	5,440	16,913
Work volume scale escalator	219	250	305	281	264	1,319
Customer growth scale escalator	177	257	320	396	514	1,664
Input cost escalation	2,047	2,848	3,925	4,460	5,345	18,625
Debt raising costs	3,991	4,257	4,396	4,458	4,485	21,587
Total operating expenditure	45,447	47,282	50,623	49,085	51,520	243,957

Table 6.1: Forecast operating expenditure 2011-15

Clause S6.1.2(1) of the Rules requires CitiPower to provide:

- its operating expenditure based on well accepted categories, being programs or types of operating expenditure. Regulatory Template 2.2 provides a detailed breakdown of CitiPower's operating expenditure, as required by the RIN and clause S6.1.2(1) of the Rules; and

- information about the extent to which its forecast operating expenditure is fixed and variable. CitiPower's business information systems do not allow it to capture this information and it cannot therefore provide this information to the AER.

However in determining the applicability of scale escalation to each element of operating expenditure, SKM determined that taxes, regulatory charges, marketing, advertising, sponsorship, CEO and corporate finance functions were invariant to scale. That is, these operating expenditure activities were considered fixed in nature.

6.2 Nature, aims and objectives

Paragraph 4.2(a)(i) of the RIN requires CitiPower to describe the nature, aims and objectives of its forecast operating expenditure for the next regulatory control period.

CitiPower's operating expenditure program principally relates to:

- the operation of the distribution system;
- the maintenance of the distribution system, and non-system, assets;
- billing, revenue collection and customer service activities related to the provision of CitiPower's network and connection services and its un-metered supplies; and
- self-insurance requirements.

CitiPower's aims from its operating expenditure program are to achieve the operating expenditure objectives in clause 6.5.6(a) of the Rules in a manner consistent with a prudent and efficient DNSP operating in CitiPower's circumstances.

CitiPower's operating expenditure forecasts therefore represent what it considers is necessary in order to:

- meet and manage the expected demand for Standard Control Services over the 2011-15 regulatory control period;
- comply with all applicable regulatory obligations; and
- ensure that its distribution system, and network, connection and metering services, meet relevant quality, reliability, safety and security of supply standards.

CitiPower has prepared its operating expenditure forecasts for 2011-15 at an aggregate level, rather than for each of the *'operating expenditure categories'* detailed in the RIN, by applying a revealed cost approach. Under this approach, the incentive properties of the ESCV's current efficiency carryover mechanism mean that CitiPower's reported results, as presented in its Regulatory Accounts prepared under *Electricity Industry Guideline No. 3 Regulatory Information Requirements* (**EIG3**), represent prudent and efficient costs.

The operation of the efficiency carryover mechanism provides significant incentives for CitiPower to minimise its operating expenditure. In the modelling that it undertook in support of its national efficiency benefits sharing scheme, the AER demonstrated that these kinds of arrangements provide a continuous incentive to improve efficiency.

This incentive is countered by the need for CitiPower to ensure that it continues to meet its regulatory obligations and to achieve its service targets.

CitiPower's efficient base year costs have been calculated based on the forecast regulatory accounts for 2009, inclusive of margin, consistent with CitiPower's proposed CAM by:

- removing abnormal and extraordinary items;
- removing licence fees;
- adding back operating expenditure liabilities paid from provisions and removing provision movements charged to operating expenditure;
- indexing the base year costs to 2010 dollars;
- adding or subtracting, as relevant, changes in scope, by applying step changes;
- adding or subtracting costs as relevant for changes in service classification;
- applying scale escalations to each category of operating expenditure underpinning the regulatory accounts, depending on the drivers that impact them;
- applying input cost escalations to each category of operating expenditure underpinning the regulatory accounts, reflecting real increases in the cost of labour, material, contractor and other costs; and
- considering any interaction between operating and capital expenditure.

CitiPower's operating expenditure forecasts for 2011-15 have been calculated applying the above approach, using forecast regulatory accounts for 2009, consistent with CitiPower's proposed CAM. By 30 April 2010, CitiPower will be able to provide the AER with its audited actual operating expenditure for 2009 and its updated operating expenditure forecasts for 2011-15 applying the above approach, using the audited actual operating expenditure for 2009.

6.3 No material projects for operating expenditure

Paragraphs 4.1(c) and 4.2 of the RIN request information from CitiPower in relation to material projects relating to operating expenditure. The term *'material projects'* is defined in the RIN.

CitiPower does not have any material projects (as defined in the RIN) that relate to its operating expenditure.

Accordingly, CitiPower does not have any information to provide the AER in response to paragraphs 4.1(c) and 4.2 of the RIN.

6.4 Key assumptions

Paragraphs 4.2(b)(ii) and 4.2(c)(vii) of the RIN, and clause S6.1.2(5) of the Rules, require CitiPower to provide information about the key assumptions that it has used in preparing its operating expenditure forecasts.

CitiPower's key assumptions for its operating expenditure forecasts are detailed in Table 6.2 together with information that addresses the requirements of paragraphs 4.2(b)(ii) and 4.2(c)(vii) of the RIN. CitiPower notes that for the purposes of complying with the RIN, it has assumed that the reference in paragraph 4.2(c)(vii) of the RIN to '*actual capex*' is a manifest error, and should instead be a reference to '*actual opex*'.

Key assumption	How the assumption has been applied or taken into account	Method and information used to develop the assumption	Quantum for purposes of paragraph 4.2(b)(ii) of RIN	Effect/impact of assumption on forecast expenditure
Recurrent 2009 expenditure *Assumption:* CitiPower's 2009 recurrent operating expenditure reflects the operating expenditure that would have been incurred by an efficient and prudent operator in order to satisfy the operating expenditure objectives.	Recurrent 2009 expenditure has been used to establish base operating expenditure for the next regulatory control period.	Recurrent 2009 expenditure has been calculated based on the forecast 2009 Regulatory Accounts. The efficiency and prudency of CitiPower's 2009 operating expenditure is detailed in Chapter 6 of this Regulatory Proposal. Recurrent 2009 establishes the base operating and maintenance expenditure for the next regulatory control period.	Table details the quantum of the forecasts for the purposes of paragraph 4.2(b)(ii) of the RIN.	There is no impact on the 2011-15 forecast operating expenditure compared to 2006-10 expenditure from this assumption because it involved the application of 2009 efficient base year expenditure
Regulatory change *Assumption:* The regulatory obligations and arrangements currently applicable to CitiPower will continue to apply in their current form throughout the 2011-15 regulatory control period (with the exception of those forecast changes that are the subject of a proposed step change). Any changes that do occur during the next regulatory control period may be the subject of a cost pass-	Except for step changes identified in section 6.9, CitiPower has prepared its forecasts on the assumption of no regulatory changes in next regulatory control period.	This assumption is based on CitiPower's existing knowledge of current or impending regulatory reviews. The assumption has been used as the basis for determining where step changes were required.	As this key assumption is made because the regulatory changes that will occur in the next regulatory control period are not known, CitiPower is not able to provide the AER with any quantum in respect of this key assumption for the purposes of paragraph 4.2(b)(ii) of the RIN.	There is no impact on the 2011-15 forecast operating expenditure compared to the 2006-10 expenditure from this assumption.

Key assumption	How the assumption has been applied or taken into account	Method and information used to develop the assumption	Quantum for purposes of paragraph 4.2(b)(ii) of RIN	Effect/impact of assumption on forecast expenditure
through.				
Step change *Assumption:* CitiPower's proposed step changes will occur and the effect on CitiPower's operating expenditure in the 2011-15 regulatory control period relative to its 2009 operating expenditure will be as forecast by CitiPower.	Step changes have used to identify the incremental increases in expenditure above and beyond the efficient 2009 base year.	CitiPower has calculated each step change based on the nature of the activity having regard for consultants' reports where relevant.	Section 6.9.3 including in particular Table 6-6 details the quantum of each of the step changes proposed by CitiPower. The total quantum of each of these step changes (which total quantum is set out in Table 6-1) represents the quantum of this key assumption for the purposes of paragraph 4.2b(ii) of the RIN.	The application of this assumption will result in an increase in operating expenditure between the 2006-10 and 2011-15 regulatory control periods to reflect the step changes.
CitiPower's policies, strategies and procedures *Assumption:* CitiPower's policies, strategies and procedures set out in regulatory template 6.4 will continue to apply in their current form throughout the 2011-15 regulatory control period.	CitiPower has prepared its forecasts on the assumption of no changes in policies, strategies or procedures in next regulatory control period.	CitiPower's internal documents and policies are based on there being no change in CitiPower's reliability targets, and those reliability targets continuing to be as set out in section 5.2.8 of this Regulatory Proposal. CitiPower has no current knowledge of any proposed change to its policies, strategies and procedures set out in regulatory template 6.4.	As this key assumption is made because CitiPower has no current knowledge of any changes to its policies, strategies and procedures that will occur in the next regulatory control period, CitiPower is not able to provide the AER with any quantum in respect of this key assumption for the purposes of paragraph 4.2(b)(ii) of the RIN.	There is no impact on the 2011-15 forecast operating expenditure compared to the 2006-10 expenditure from this assumption.
Forecasts of customer numbers *Assumption:* Customer growth over	Forecast customer numbers have been used to calculate the customer growth scale escalator.	The forecast of customer numbers for the period 2011-15 has been prepared by independent modelling	The quantum of this key assumption is reflected in Table 6-1 in the row titled customer growth scale	The 2011-15 forecast operating expenditure is higher than the 2006-10 expenditure on account of the

Key assumption	How the assumption has been applied or taken into account	Method and information used to develop the assumption	Quantum for purposes of paragraph 4.2(b)(ii) of RIN	Effect/impact of assumption on forecast expenditure
the 2011-15 regulatory control period will be as forecast in Regulatory Template 6.3.		experts NIEIR. Refer Chapter 4 of this Regulatory Proposal, including for the quantum of the forecasts for the purposes of paragraph 4.2(b)(ii) of the RIN. Customer growth is incorporated into the scale escalation calculation.	escalator.	increase in customer numbers.
Labour cost escalators *Assumption:* Nominal wage growth for CitiPower in the 2011-15 regulatory control period will be as forecast in the labour cost escalators outlined in Chapter 7 of this Regulatory Proposal.	Operating expenditure is segregated into labour, materials and contracts/other costs. Labour escalators have been applied to adjust the labour cost components of operating expenditure forecasts for the forecast changes in labour costs over the next regulatory control period. Refer to Chapter 7 of this Regulatory Proposal.	The forecast nominal labour escalators for the period 2011-15 have been prepared by independent consultants BIS Shrapnel. Refer also to Chapter 7 of this Regulatory Proposal. Labour cost escalators have been applied to the labour component of forecast operating and maintenance expenditure.	Refer to Chapter 7 of this Regulatory Proposal, including for the quantum of the escalation for the purposes of paragraph 4.2(b)(ii) of the RIN.	The impact of adjusting for nominal wage growth is an increase in the labour component of the 2011-15 forecast operating expenditure as determined by the labour cost escalators outlined in Chapter 7 of this Regulatory Proposal.

Key assumption	How the assumption has been applied or taken into account	Method and information used to develop the assumption	Quantum for purposes of paragraph 4.2(b)(ii) of RIN	Effect/impact of assumption on forecast expenditure
Contracts/other cost escalator *Assumption*: Nominal contracts/other cost growth for CitiPower in the 2011-15 regulatory control period will be as forecast in the outsourced services wage escalator detailed in Chapter 7 of the Regulatory Proposal.	Operating expenditure is segregated into labour, materials and contracts/other costs. Contracts/other cost escalators have been applied to adjust the contracts/other cost component of operating expenditure forecasts for the forecast changes in contracts/other costs over the next regulatory control period. Refer to Chapter 7 of this Regulatory Proposal.	The forecast of CitiPower's nominal contracts/other cost growth for the period 2011-15 has been prepared by independent consultants BIS Shrapnel. Refer to Chapter 7 of this Regulatory Proposal. Contracts/other costs escalators have been applied to those cost components of forecast operating and maintenance expenditure not deemed labour or materials.	Refer to Chapter 7 of this Regulatory Proposal, including for the quantum of the escalation for the purposes of paragraph 4.2(b)(ii) of the RIN.	The impact of adjusting for contracts/other cost growth is an increase in the contracts/other costs component of the 2011-15 forecast operating expenditure as determined by the outsource services wage escalator detailed in Chapter 7 of the Regulatory Proposal.
Materials cost escalators *Assumption:* The nominal escalations in the cost of materials over the 2011-15 regulatory control period will be as forecast in the material cost escalators outlined in Chapter 7 of this Regulatory Proposal.	Operating expenditure is segregated into labour, materials and contracts/other costs. Material escalators have been applied to adjust the materials cost component of operating expenditure forecasts for the forecast changes in material costs over the next regulatory control period. Refer to Chapter 7 of this Regulatory Proposal.	The forecast nominal material cost escalators for the period 2011-15 have been prepared by independent consultants Sinclair Knight Merz (SKM). Refer Chapter 7 of this Regulatory Proposal. Material escalators have been applied to the material component of forecast operating and maintenance expenditure.	Refer to Chapter 7 of this Regulatory Proposal, including for the quantum of the escalation for the purposes of paragraph 4.2(b)(ii) of the RIN.	The impact of adjusting for the changes in the cost of materials is an increase in the materials cost component of the 2011-15 forecast operating expenditure as determined by the materials cost escalator detailed in Chapter 7 of the Regulatory Proposal.
Forecast inflation	Forecast annual inflation over 2011	This inflation forecast is based on	There are numerous interrelated	Forecast real expenditure will differ

Key assumption	How the assumption has been applied or taken into account	Method and information used to develop the assumption	Quantum for purposes of paragraph 4.2(b)(ii) of RIN	Effect/impact of assumption on forecast expenditure
Assumption: Forecast annual inflation over 2011-15 will be equal to the geometric average of annual inflation forecasts over the ten year period starting from 2011 using RBA annual inflation forecasts where available and otherwise using the mid-point of the RBA inflation target range.	to 2015 is used to convert the nominal escalators to real escalators and to convert 2010 real expenditure and revenue forecasts to nominal expenditure and revenue forecasts.	the AER's preferred approach as set out in the New South Wales Final Determination. Forecast annual inflation over 2011-15 is used to convert the nominal escalators to real escalators and to convert 2010 real expenditure and revenue forecasts to nominal expenditure and forecasts.	key drivers influencing the quantum of operating expenditure. It is therefore not possible to discern the discrete quantum impact of forecast inflation on the forecast expenditure.	from actual 2006-10 real expenditure by the inflation adjusted nominal cost escalators, all else being equal. Forecast nominal expenditure is independent of the inflation forecast.
Unit rates applied to key items of plant and equipment for both labour and material unit rates Assumption: The unit rates incurred by CitiPower in 2009 and therefore reflected in the 2009 base year will be the unescalated unit rates incurred by CitiPower in the 2011-15 regulatory control period. The unescalated unit rates comprise a labour, materials and contract component. Each component is separately adjusted by relevant escalator (labour, materials and contract) as discussed above.	This assumption applies to the forecasting of operating expenditure. Refer to Chapter 7 of this Regulatory Proposal.	CitiPower internally derives its input costs on the basis of the current average costs of undertaking similar projects and capital work programs over the current regulatory control period. These unit rates represent an aggregation of materials and other costs such as labour and other costs required to complete the works.	No specific information is available with respect to the quantum of this key assumption. However the quantum of this assumption is reflected in the 2009 base operating expenditure set out in table 6-1.	There is no impact on the 2011-15 forecast operating expenditure compared to the 2006-10 expenditure resulting from the unit rates key assumption. Unescalated unit rates are simply derived from 2006-10 expenditure.

Key assumption	How the assumption has been applied or taken into account	Method and information used to develop the assumption	Quantum for purposes of paragraph 4.2(b)(ii) of RIN	Effect/impact of assumption on forecast expenditure
2010 indexation *Assumption:* 2009 dollars are related to 2010 dollars by CPI.	This assumption is applied to escalate $2009 operating expenditure to $2010 operating expenditure forecasts as required by the AER's RIN. CitiPower determined its base operating expenditure in $2009 for internal purposes. Refer to Chapter 7 of this Regulatory Proposal.	This CPI assumption is based on the most recently available RBA forecast as required and specified by the AER's Regulatory Templates.	No specific information is available with respect to the quantum of this key assumption. However the quantum of this assumption is reflected in the 2009 base operating expenditure set out in Table 6-1.	There is no impact on the 2011-15 forecast expenditure compared to the 2006-10 expenditure resulting from the application of this assumption.
Scale escalation *Assumption:* The effect of network growth, growth in work volume and customer growth on CitiPower's 2011-15 operating expenditure will be as reflected by the application of the scale escalators, set out in Table 6.3, to 2009 operating expenditure.	The three components for scale escalation, network growth, growth in work volume and customer growth have been applied to forecast operating expenditure to account for increases in scale over the next regulatory period.	CitiPower has internally developed a scale escalation model similar to that proposed by ETSA Utilities and ElectraNet. The application of the approach has been verified by SKM. Refer to section 6.9.2 of this Regulatory Proposal. Scale escalation is applied to forecast operating and maintenance expenditure based on the nature of expenditure.	The quantum of this key assumption is the sum of the rows in Table 6-1 titled *'Network growth scale escalator'*, *'Customer growth scale escalator'* and *'Work volume scale escalator'*.	The application of this assumption will result in an increase in operating expenditure between the 2006-10 and 2011-15 regulatory control periods to reflect scale escalation.

Key assumption	How the assumption has been applied or taken into account	Method and information used to develop the assumption	Quantum for purposes of paragraph 4.2(b)(ii) of RIN	Effect/impact of assumption on forecast expenditure
Forecasts of spatial peak demand Assumption: Spatial peak demand in the 2011-15 regulatory control period will be as forecast in Regulatory Template 6.3.		Spatial forecast peak demand levels for the period 2011-15 have been developed internally by CitiPower and cross checked against independent forecasts prepared by NIEIR and AEMO. Refer Chapter 4 of this Regulatory Proposal. Spatial demand is relevant to the determination of the network growth calculation which is incorporated in the scale escalation calculation.	The quantum of this key assumption is reflected in Table 6-1 in the row titled '*Network growth scale* escalator'.	Spatial peak demand has driven an increase in network assets and associated workloads. These are both inputs into the scale escalation model, which is discussed above.

Table 6.2: Key operating expenditure assumptions

As required by clause S6.1.2(6) of the Rules, the reasonableness of the key assumptions that underlie CitiPower's operating expenditure forecasts were certified CitiPower's Board as set out in Chapter 26 of this Regulatory Proposal.

While paragraph 4 of the RIN, including in particular paragraph 4.2(b)(ii) of the RIN does not impose any obligations on CitiPower to identify the *'key drivers or inputs'*, as defined by the AER in the RIN, used in the preparation of CitiPower's forecast operating expenditure proposal, CitiPower observes for completeness that the following *'key drivers or inputs'* are not relevant to the operating expenditure forecasts in this Regulatory Proposal:

- forecasts of utilisation levels;
- forecast of weighted average remaining life of assets; and
- forecasts of line length.

These matters have therefore not been considered in developing CitiPower's forecast operating expenditure for the next regulatory control period.

6.5 Regulatory obligations or requirements

Paragraph 4.2(b)(iv) of the RIN requires CitiPower to identify each regulatory obligation or requirement of relevance to its forecast operating expenditure.

CitiPower does not explicitly build up its operating expenditure forecast by reference to regulatory obligations or requirements. Rather, compliance with these obligations or requirements are reflected in the 2009 base operating expenditure. For this reason, CitiPower is unable to provide the AER with a definitive and comprehensive list of each and every regulatory obligation or requirement of relevance to its forecast operating expenditure.

Nonetheless, CitiPower observes the it is subject to a number of service standard, and other regulatory, obligations under the *National Electricity (Victoria) Act 2005* (**NEL**), *Electricity Industry Act 2000* and *Electricity Safety Act 1998*. Various other legislation, including occupational health and safety (**OHS**) and the environment, also directly impact on CitiPower's works and activities. New regulatory measures relating to climate change will also affect CitiPower, such as the Carbon Pollution Reduction Scheme, Energy Efficiency Opportunities Act 2007, the Renewable Energy Target and the Victorian Energy Efficiency Target Scheme.

The *Electricity Industry Act 2000* and *Electricity Safety Act 1998* give power to a large amount of subordinate legislation, with which CitiPower must comply. These include the *Electricity Distribution Licence*, *Electricity Distribution Code*, *Electricity Industry Guidelines*, *Electricity Safety (Network Asset) Regulations 1999*, *Electricity Safety (Electric Line Clearance) Regulations 2005* and *Electricity Safety (Bushfire Mitigation) Regulations 2003*.

CitiPower has provided the completed Regulatory Template 4.1 as part of this Regulatory Proposal, which provides a more detailed list of its regulatory obligations and requirements.

Many of the economic regulatory instruments that apply to CitiPower were previously administered by the Essential Services Commission of Victoria (**ESCV**). These include the *Electricity Distribution Licence*, the *Electricity Distribution Code* and the *Electricity Industry Guidelines*. The transition to a national regulatory framework and to the AER has created some uncertainty as to the future of these documents and the basis on which these documents could be amended. For the purposes of this Regulatory Proposal, CitiPower has assumed that, unless otherwise identified, the current arrangements will apply.

6.6 Network planning standards

Paragraph 4.2(c)(v) of the RIN requires CitiPower to identify how relevant network planning standards have been incorporated into its forecast operating expenditure.

CitiPower has not included an explicit allowance in its operating expenditure forecasts for meeting its network planning standards, although its base year necessarily reflects the efficient operating expenditure that is required to operate and maintain its assets in a manner that enables it to achieve these standards. This is because the unit rates incurred by CitiPower enable it to meet these requirements and these unit rates are reflected into the current average costs of works in the 2009 operating expenditure base year.

CitiPower has assumed, for the purposes of preparing its forecast operating expenditure, that its network planning standards will continue to apply in their current form throughout the next regulatory control period. CitiPower has not included any step change in its forecasts for any increased operating expenditure associated with achieving these standards, although the scale escalators that are incorporated into the forecasts are designed to ensure that it continues to meet these standards as demand on its network grows.

6.7 Reliability targets

Paragraph 4.2(c)(iv) of the RIN requires CitiPower to identify how relevant reliability targets have been incorporated into its forecast operating expenditure.

CitiPower has not included an explicit allowance in its operating expenditure forecasts for meeting its reliability targets, although its base year necessarily reflects the efficient operating expenditure that is required to operate and maintain its assets in a manner that enables it to achieve these targets. This is because the costs incurred by CitiPower enable it to meet these requirements and are reflected into the 2009 operating expenditure base year.

CitiPower is not proposing any improvements in reliability targets in the next regulatory control period through this Regulatory Proposal. It has therefore not included any step change in its forecasts for any increased operating expenditure associated with achieving higher targets, although the scale escalators that are incorporated into the forecasts are designed to maintain current reliability levels.

Clause S6.1.2(4) of the Rules requires CitiPower to detail the method used for determining the cost associated with planned maintenance programs designed to improve the performance of the distribution system for the purposes of the STPIS. CitiPower notes that none of its forecast maintenance expenditure is designed to improve the performance of its distribution system, including for the purposes of the STPIS.

6.8 Policies, strategies, procedures and consultants' reports

Paragraphs 4.2(b)(i), 4.2(c)(i) and 4.2(c)(vi) of the RIN require CitiPower to provide information in relation to policies, strategies, procedures and consultants' reports that have been used in preparing its forecast operating expenditure.

The completed Regulatory Template 6.4, that has been provided with this Regulatory Proposal, lists and describes the key internal plans, policies, procedures or strategies that are currently used by CitiPower to plan and conduct its day to day operations. It also describes the nature, reason and impact of any change in these documents during the current regulatory control period.

CitiPower has not explicitly built up its operating expenditure forecasts based on its plans, policies, procedures and strategies, although its base year necessarily reflects the efficient operating expenditure that is required to operate and maintain its assets in a manner consistent with these documents. This is because the costs incurred by CitiPower have been prepared by applying these documents and these costs are reflected into the current average costs of works in the 2009 operating expenditure base year.

CitiPower has assumed, for the purposes of preparing its forecast operating expenditure, that these documents will continue to apply in their current form throughout the next regulatory control period. It has not included any step change in its forecasts for any increased operating expenditure associated with applying these documents. However, the scale escalators that are incorporated into the forecasts are designed to ensure that it continues to implement these documents as demand on its network grows.

CitiPower has relied on the following consultants' reports in preparing its operating expenditure forecasts:

- BIS Shrapnel in relation to labour cost escalators and contract and other cost escalators;
- SKM in relation to material cost escalators;
- Aon Risk Services Australia Ltd (Aon) in relation to insurance and self insurance costs;

- NIEIR in relation to growth in customer numbers;
- AECOM in relation to the impacts of climate change;
- Competition Economists Group in relation to debt raising costs - this report was commissioned by ETSA Utilities;
- KPMG in relation to the efficiencies of CitiPower's service provision model;
- Ernst and Young in relation to the commercial benchmark for the margins applied in the provision of corporate services and network services under CitiPower's service provision model; and
- SKM in relation to the impact of scale on operating expenditure forecasts over the next regulatory control period.

CitiPower has not departed from any of the conclusions and recommendations of these consultants' reports in preparing its operating expenditure forecasts. Each of these reports has been provided to the AER with this Regulatory Proposal.

6.9 Methodology

Paragraph 4.2(c)(iii) of the RIN and clause S6.1.2(2) of the Rules require CitiPower to explain the methodology that it has used to develop its forecast operating expenditure for the next regulatory control period.

As noted above, CitiPower has applied a revealed cost approach to determining its operating expenditure forecasts. This is a widely accepted regulatory approach and was applied by the ESCV in its 2006-10 EDPR for the current regulatory control period. CitiPower therefore considers that it is appropriate to apply this revealed cost approach to determine the operating expenditure building block for the next regulatory control period.

The revealed cost approach has involved applying a base line and step change approach to the total operating expenditure forecast by:

- establishing the efficient recurrent operating expenditure for the base year (2009) attributable to Standard Control Services, including by adjusting for provisions, removing abnormals and extraordinaries and indexing the base year costs to 2010 dollars based on CPI;
- adding/subtracting changes in scope or service classification;
- applying scale escalations to each category of operating expenditure, depending on the drivers that impact upon each expenditure category;
- applying input cost escalation, reflecting real increases in the cost of labour, materials and contracts and other costs; and
- considering any interaction between operating and capital expenditure.

This approach is illustrated diagrammatically in Figure 6-1 and described in detail below.

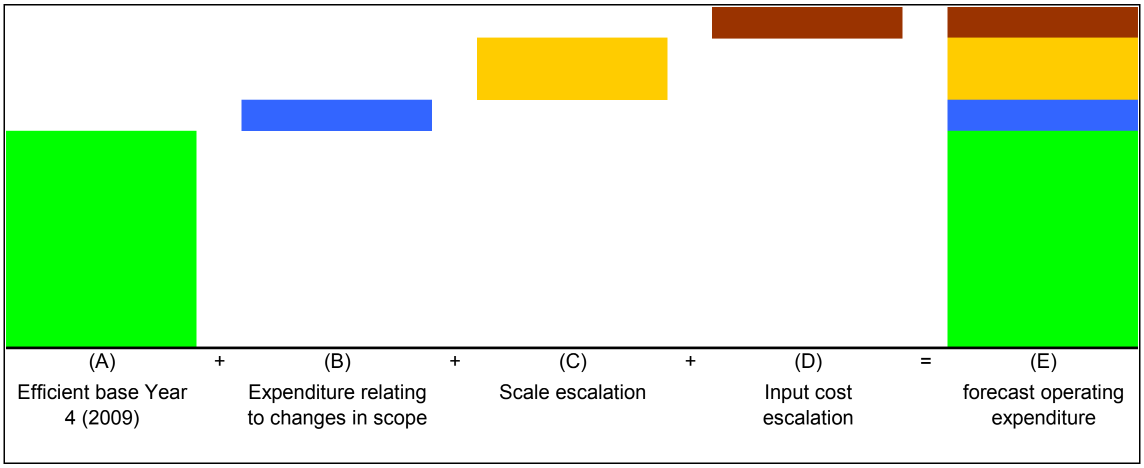

Figure 6-1: Operating expenditure forecast methodology

6.9.1 Justification of efficient base year

Paragraphs 4.2(b)(iii) and 4.2(c)(ix) of the RIN require CitiPower to identify and justify the efficient operating expenditure base year.

CitiPower considers the fourth year of the current 2006-10 regulatory control period – ie 2009 – to be an efficient base year. The unit costs inherent in the operating expenditure forecasts are therefore based on CitiPower's historic costs, ie 2009 costs. CitiPower considers that 2009 is the most efficient base year because it:

- will include the most recent year of actual outturn data. Audited regulatory accounts will be available by 30 April 2010 before the AER is required to make its Draft Distribution Determination;
- best reflects the impact of the economic conditions that are likely to prevail during the 2011-15 regulatory control period; and
- aligns CitiPower's operating expenditure forecast with the operation of the efficiency carryover mechanism that applies to it in the current regulatory control period.

CitiPower's efficient operating expenditure base year has been calculated from the forecast regulatory accounts for 2009, consistent with CitiPower's proposed CAM. By 30 April 2010, CitiPower will be able to provide the AER with its audited actual operating expenditure for 2009 and its updated efficiency carryover calculation.

CitiPower's operating costs for 2009 can be considered efficient because it:

- has been, and remains, subject to an efficiency benefit sharing scheme that provides financial incentives to achieve ongoing operating expenditure efficiency savings; and

- operates in a commercial environment, which requires it to continuously pursue cost efficiency savings, whilst meeting its ongoing service targets and regulatory requirements.

CitiPower also notes the reduction in operating expenditure that it has achieved over the current regulatory control period, as detailed in section 6.14 provides further evidence that the unit costs underlying the forecast operating expenditure can be considered efficient.

CitiPower confirms that there are no non-recurrent or one-off costs that should be excluded from the 2009 operating expenditure base year.

6.9.2 Scale adjustment

Clause S6.1.2(8) of the Rules requires CitiPower to explain any significant variations in its forecast operating expenditure from its historic operating expenditure. For the purposes of developing its forecast operating expenditure, CitiPower interprets this to include scale adjustments that should apply to the 2009 operating expenditure base year in the next regulatory control period.

DNPSs' operating expenditures are generally recognised to be dependent upon the scale of their operations. Recognising this, CitiPower has developed a scale escalation model similar to that used by ETSA Utilities[36] and ElectraNet[37] in their recent Regulatory and Revenue Proposals to the AER.

CitiPower has determined that operating expenditure over the next regulatory control period will be subject to three major growth factors. These factors are:

- network growth – this takes into account the growth in the size of the distribution network;
- growth in work volume – this takes into account changes in the volume of capital and maintenance activity on the network; and
- customer growth – this takes into account changes in customer numbers.

Scale escalators

CitiPower considers that only some types of operating expenditure will grow in direct proportion to the three identified scale escalators. As a consequence, CitiPower has adopted the ETSA Utilities methodology of applying economy of scale factors to broad groups of operating expenditure activities that are driven by similar factors. In determining the economy of scale factors, CitiPower has been guided by Sinclair Knight Merz's independent assessment of the impact of scale escalators on each operating and maintenance expenditure category.

[36] ETSA Utilities, Regulatory Proposal 2010-2015, 1 July 2009, p.171.
[37] ElectraNet, ElectraNet Transmission Network Revenue Proposal – Volume 1, 1 July 2008 to 30 June 2012

Derivation of network growth escalator

CitiPower has forecast the growth in its distribution network over the next regulatory control period by calculating the percentage increase in CitiPower's undepreciated regulated asset base for electricity distribution assets, using the following formula:

$$\frac{\textit{(Reinforcements + Gross New Customer Connections – Retirements)}}{\textit{Undepreciated RAB}}$$

The resultant network growth factor verified by SKM is shown in Table 6.3.

	Cumulative %					
Description	2010	2011	2012	2013	2014	2015
Network growth	2.8	8.3	14.1	20.0	25.4	30.4

Table 6.3: Network growth escalator

Derivation of work volume escalator

Direct field work arising from CitiPower's work program will increase its operating expenditure over the next regulatory control period. The forecast increase has been calculated by taking the forecasts of capital and operating expenditure and providing them to CitiPower's current provider of field resources, Powercor Network Services. Powercor Network Services have forecast the increase in full time equivalent trade skilled workers that will be required to deliver the expenditure programs. These forecasts are detailed in Table 6.4 and have been verified by SKM.

	Cumulative %					
Description	2010	2011	2012	2013	2014	2015
Work volume	16.9	50.1	57.1	66.8	57.6	50.5

Table 6.4: Work volume escalator

Derivation of customer growth escalator

Operating expenditure associated with billing, revenue collection and customer services is driven by changes in customer numbers, as these services are supplied directly to customers.

As noted in Chapter 4, CitiPower engaged NIEIR to develop independent customer growth forecasts for the next regulatory control period. In developing the customer growth escalator, CitiPower has used NIEIR's total customer growth forecasts.

	Cumulative %					
Description	2010	2011	2012	2013	2014	2015
Change in customer numbers	1.6	3.8	5.5	6.6	7.9	10.0

Table 6.5: Customer growth escalator

The detailed calculation of each scale escalator and how it applies by operating expenditure category is presented in Attachment C0061.

6.9.3 Step changes

Paragraphs 4.2(a)(ii), 4.2(b)(v) and 4.2(c)(viii) of the RIN require CitiPower to provide information about its proposed step changes that are relevant to the development of its operating expenditure forecasts. That information is set out in this section 6.9.3.

In addition, clauses S6.1.2(3) and S6.1.2(8) of the Rules require CitiPower to provide information about the key variables that have been used to prepare the operating expenditure forecasts, as well to explain any significant variations in its forecast operating expenditure from its historic operating expenditure. For the purposes of developing its forecast operating expenditure, CitiPower interprets this to include step changes that should apply to the 2009 base year operating expenditure base year in the next regulatory control period.

Clause 6.5.6(c) of the Rules provides that:

> *'The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects:*
>
> *(1) the efficient costs of achieving the operating expenditure objectives; and*
>
> *(2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and*
>
> *(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.*
>
> *(the operating expenditure criteria).'*

The 2009 operating expenditure base year reflects the efficient costs a prudent operator in the circumstances of CitiPower would require to meet the operating expenditure objectives, based on CitiPower's current operating environment and having regard to its current service targets and regulatory obligations and other relevant prevailing circumstances. However, in the next regulatory control period a prudent operator in the circumstances of CitiPower would be required to undertake new or increased activities, and to incur new or increased costs associated with step changes detailed in Table 6.6 in order to continue to achieve the operating expenditure objectives. These step changes are described below. Note that the value of the step changes listed in Table 6.1 and Table 6.6 are inclusive of overheads, which are applied to maintenance activities.

	$'000 (2010)					
Description	2011	2012	2013	2014	2015	Total
Increased activities due to the effects of climate change	688	296	297	299	300	1,880
Insurance premiums	777	1,094	1,412	1,710	2,026	7,019
Self insurance	131	138	139	139	139	686
The national framework for distribution network planning and expansion	633	478	604	483	522	2,720
Customer charter	424	-	-	-	-	424
Electrical Safety Management Regulations	274	272	273	275	275	1,369
[redacted]						
Total	5,787	5,653	6,425	2,906	3,262	24,033

Table 6.6: CitiPower's operating expenditure step changes[38]

CitiPower notes that the RIN seeks to define a *'step change'* as *'a new, changed or ceased regulatory obligation or requirement'*. In its response to submissions received on the Draft RIN in respect of the RIN definition of *'step change'*, the AER observed that:

> *'[t]he AER requires that for the purposes of the regulatory proposal, step changes are limited to those changes (including service standards) that are new, changed or ceased regulatory obligations and requirements'.*

For the purposes of compliance with the RIN, CitiPower has identified in this section 6.8.3 each step change that meets the RIN definition of 'step change'.

However, CitiPower notes that this definition in the RIN does not have the effect of preventing CitiPower from proposing step changes that are not related to new, changed or ceased regulatory obligations or requirements. The AER has no power under the NEL, Rules or the RIN to prevent a DNSP from providing additional information in its Regulatory Proposal.

In any event, there is no reason for the AER to seek to limit the changes that may be proposed by DNSPs as step changes and any attempt to do so would be inconsistent with the Rules governing the AER's consideration of a DNSP's forecast of operating

[38] Excludes overheads

expenditure. The NEL definition of *regulatory obligations or requirements* is relevant to the definition of *pass-through events* in the Rules, but that term has no relevance under the Rules in respect of determining forecast operating expenditure. The test that the AER must apply when determining whether to accept CitiPower's forecast of operating expenditure is the test set out in clause 6.5.6(c) of the Rules, ie does the forecast reasonably reflect the operating expenditure criteria set out in that clause.

As required by paragraph 4.2(a) of the RIN, CitiPower identifies in this section 6.10, as relevant, supporting material that demonstrates each *'step change'* identified.

Clause 6.5.6(c) requires the operating expenditure forecast to reflect the costs that a prudent operator in the circumstances of CitiPower would require to achieve the operating expenditure objectives. This requirement means that the forecasts must take into account all relevant changes in the circumstances of CitiPower, not just those changes that relate to a new, changed or ceased regulatory obligation or requirement.

For the purposes of paragraph 4.2(c)(viii)(2) of the RIN, all of the step changes except the step changes related to the customer charter and the West Melbourne demand management initiative are recurrent in nature.

For the purposes of compliance with paragraph 4.2(c)(viii)(3) of the RIN, the step changes related to climate change, the national framework for distribution network planning and expansion, the customer charter and the proposed *Electricity Safety (Management) Regulations 2009* are wholly or partly related to environment, safety or legal regulatory obligations or requirements. However, CitiPower notes that this RIN question is irrelevant for the purposes of the tests that the AER is required to apply under clause 6.5.6 of the Rules and is in no way determinative of whether a step change must be accepted by the AER under clause 6.5.6(c).

Increased activities due to the effects of climate change

Climate change is no longer a fringe environmental issue but is now a fundamental policy and practical challenge that is facing all of humanity, including Australian State and Federal Governments and industry.

As the largest and fastest growing source of national greenhouse gas emissions, the energy sector is understandably a key focus of the climate change agenda. As is discussed in section 6.5, key regulatory measures such as the *Carbon Pollution Reduction Scheme*, *Energy Efficiency Opportunities Act 2007*, the *Renewable Energy Target* and the *Victorian Energy Efficiency Target Scheme* are rapidly changing the environment in which DNSPs, such as CitiPower, operate.

The impact of climate change on CitiPower's load forecasts was discussed in Chapter 4 but climate change also has direct implications for the physical performance of CitiPower's distribution system. Changing climatic conditions, such as increased average temperatures and decreased average rainfalls alter the performance of network assets that have been designed to cope with the historic climate. Further, increasingly extreme weather events, such as 2 April 2008 wind storms and the heatwave of January 2009, impact directly on network performance and operating costs.

Managing the impacts of climate change on the network has been a key consideration in CitiPower's thinking over the past three years. In order to enable it to understand climate change better and to quantify its impacts on the network, CitiPower engaged AECOM to prepare a report entitled *Assessment of Climate Change Impacts on CitiPower Network for 2011-15 EDPR: Maintaining Network Reliability in a Changing Environment*. The report was commissioned following an earlier review in 2007 that was also prepared by AECOM[39], which made a number of recommendations relating to CitiPower's strategies for mitigating the risk of climate change.

AECOM's approach involved firstly identifying potential impacts on CitiPower's network and then commissioning climate change scenario modelling from the Commonwealth Scientific and Research Organisation (**CSIRO**). Analysis was performed of CitiPower's historical network performance data and historical climate data for the Melbourne area (obtained from the Bureau of Meteorology and Global Positioning and Tracking Systems). An analysis and review was also performed of climate change policies proposed or already introduced by State or Federal Government's and trends in energy technology. From this analysis, AECOM performed quantification of impacts of policy and technology trends on sales and capital expenditure and quantification of projected climatic change impacts on network expenditure.

In order to continue to achieve the operating expenditure objectives, a prudent operator in the circumstances of CitiPower would be required to undertake increased activities and incur increased operating expenditure in the next regulatory control period as a result of the impacts of climate change identified by AECOM.

In particular, it is critical that CitiPower take action to address climate change in order to meet the following operating expenditure objectives over the next regulatory control period, and beyond:

- maintain the quality, reliability and security of supply of *standard control services* (clause 6.5.6(a)(3) of the Rules); and
- maintain the reliability, safety and security of the *distribution system* through the supply of *standard control services* (clause 6.5.6(a)(4) of the Rules).

Not taking the actions identified by AECOM would reflect imprudent management of the distribution system and would potentially expose customers to declining service performance in the next regulatory control period, and beyond. The operating expenditure forecast included in this Regulatory Proposal in relation to the climate change step change has been reviewed and tested by AECOM and is prudent and efficient. Table 6.7 details the operating expenditure consequences of climate change as identified by AECOM in the next regulatory control period.

[39] Maunsell AECOM, Watts Next? Climate Change and Environmental Issues and Trends Assessment for Energy Distribution Services in Melbourne, Western Victoria and South Australia, 9 November 2007.

Impact quantified	Key finding
Effect of climate change on fault costs	Projections from the CSIRO[40] indicate a material increase in the average frequency of high wind days in 2015 compared to 2008. AECOM have estimated the SAIDI impact to be between 2.1 and 6.5 minutes. Based on the projected increase in very high and extreme fire risk days determined by AECOM, and the increased incidence of faults due to wind identified by AECOM, CitiPower's operating costs will increase by a total of \$1.5m (\$2010) over the period 2011-15.
Asset review	Climate change will produce a gradual shifting of the fundamental assumptions upon which network equipment is designed and procured. Ambient air temperature, wind speed, ambient soil temperature and rainfall are all expected to impact of network equipment. AECOM have recommended CitiPower undertake a series of risk reviews targeting circuit breaker ratings, underground cable ratings and overhead line ratings as a prelude to making changes to existing design or procurement practices. The total cost of the reviews is forecast by AECOM to be \$0.4m (\$2010).

Table 6.7: Key findings of climate change impact 2011-15

It should be noted that AECOM also considered the capital expenditure consequences of these items identified above. These capital expenditure items have been incorporated in Chapter 5 of this Regulatory Proposal.

Table 6.8 quantifies the operating expenditure step change related to climate change in the next regulatory control period.

	$'000 (2010)					
	2011	2012	2013	2014	2015	Total
Climate change	688	296	297	299	300	1,880

Table 6.8: Step change related to climate change 2011-15 ($'000 2010)

Insurance premiums

CitiPower relies on a mix of insurance, self insurance and pass-through events to manage the various risks that it faces.

The categories of insurance for which CitiPower obtains insurance cover include: aviation, brokers fees, corporate travel, crime, industrial special risk (property), inpatriate, liability, motor vehicle, and personal accident.

CitiPower's experience is that its insurance premiums are largely driven by external factors, such as the state of the global economy and specific catastrophic events that have occurred round the world, as opposed to changes in the risk profile of CitiPower's own assets.

In order to forecast operating expenditure associated with its insurance premiums during the next regulatory control period, CitiPower engaged its insurance broker, Aon, to provide an estimate of its insurance costs to 2015. In providing its estimates,

[40] CSIRO Mk3.5 and HADGEM1

Aon specifically considered CitiPower's business trends, broad trends in the insurance market and CitiPower's risk management and insurer relationships.

Aon's report entitled *CitiPower Pty - Price Reset – Insurance Cost Projections* identified that CitiPower's insurance premiums are likely to increase considerably in the next regulatory control period, as detailed in Table 6.9. Aon's report has been provided to the AER with this Regulatory Proposal.

	$'000 (2010)					
	2011	2012	2013	2014	2015	Total
Insurance premiums	777	1,094	1,412	1,710	2,026	7,019

Table 6.9: Change in insurance premiums 2011-15

In Aon's view, there are several key factors that are likely to drive a period of above average rate increases for CitiPower's liability insurance, including:

- the record maximum temperatures in 2008 and 2009, the Victorian bushfires of 7 February 2009 and other bushfires that have taken place around the world, which contribute to potential increases in the future risks of catastrophic fire losses;
- the losses faced by unrelated companies negatively impacting the limited number of liability insurers who provide cover to electricity transmission and distribution businesses; and
- the need for insurers to increase underwriting revenues in order to sustain their businesses.

Appropriate insurance coverage is a critical element of CitiPower's approach to risk management and it is not an option for it to avoid taking out the appropriate insurance coverage by not paying the increased premiums. A prudent operator in CitiPower's circumstances would ensure that it maintains the appropriate level of insurance cover at all times. A prudent operator would accordingly be required to pay the increased premiums that have been forecast in Aon's report. Having this insurance coverage ensures that CitiPower can prudently manage the costs of unforseen events that may otherwise compromise its ability to maintain the reliability, safety or security of its distribution system and therefore meet the operating expenditure objectives in clause 6.5.6(a)(4) of the Rules.

Debt raising costs

CitiPower has included debt raising costs as a component of its operating expenditure forecast. The nature of debt raising is such that it is constantly being refreshed as debts mature and businesses' require refinancing. Debt raising costs are not reported in CitiPower's operating or capital expenditure in its Regulatory Accounts and therefore a separate benchmark forecast has been included in the building block for the next regulatory control period.

In the AER's *Final Decision New South Wales distribution determination 2009-10 to 2013-14* (**NSW Final Determination**), the AER accepted that debt raising costs:

- are incurred each time that debt is rolled over;
- may include underwriting fees, legal fees, company credit rating fees and other transaction costs; and
- are a legitimate expense for which a DNSP, such as CitiPower, should be provided an allowance.[41]

Debt raising costs are generally measured in basis points per annum (**bppa**). In the NSW Final Determination, the AER concluded that the benchmark debt raising costs for corporate bond issues could range from 10.4 bppa for a single corporate bond issue of $200 million, to 8.0 bppa for 25 corporate bond issues of $5,000 million in total.

ETSA Utilities as part of its *ETSA Utilities Regulatory Proposal 2010-2015* engaged the Competition Economists Group (**CEG**) to provide an expert opinion on direct debt raising costs[42]. This expert opinion considered matters including the appropriate criteria that should be applied when selecting sources of data from which the cost of raising debt should be determined and how these criteria could be applied in the current context.

CEG's report is provided as Attachment C0059 of this Regulatory Proposal. CitiPower requested CEG to update the calculation of debt underwriting costs and to update debt non-underwriting costs for inflation. CEG's letter is provided as Attachment C0200 of this Regulatory Proposal. CEG concludes that based on the updated results a conservative estimate of underwriting costs is 9.4 basis points per annum and an inflation estimate of 10.2 per cent should be applied to the AER's estimate of debt non-underwriting costs.

The AER's estimate of legal, road show, registry fees and paying fees are expressed in dollars per issue tranche. Inflation increases the total amount of debt to be raised, and therefore the AER's estimated cost should be escalated by inflation. By contrast, the issue credit rating cost estimate is expressed as a percentage of the issue value and will automatically be escalated for increases in the issue size and/or number of issues as a result of inflation. Therefore this cost should not be additionally inflated.

The following basis points per annum fees are (using the annualised debt costs of 10.19 per cent to amortise the upfront debt costs over ten years) are set out in Table 6.10.

[41] AER, Final Decision on the New South Wales Distribution Determination 2009-2010 to 2013-2014, 28 April 2009, page 183.
[42] ETSA Utilities, ETSA Utilities Regulatory Proposal 2010-2015, Attachment E.17.

Debt raising fees	Basis points per annum
Issue rating agency fees	1.1
Legal and roadshow costs	1.3
Registry fees	0.2
Paying fee	0.1
Total	2.7
Total inflated by 10.2 per cent	2.9

Table 6.10: Debt raising fees

On the basis of CEG's report and letter it has been determined that an appropriate benchmark for CitiPower's direct debt raising costs is 12.3 basis points per annum. This figure is applied to 60 per cent of the Standard Control Service regulatory asset base which is that benchmark proportion of the RAB that is financed by debt, to calculate CitiPower's benchmark direct debt raising costs.

In addition to direct debt raising costs, CitiPower faces additional costs in refinancing its debt, which in the current economic climate are significant. For the purpose of managing liquidity risk, the credit rating agencies seek to ensure that impending maturing debt is being appropriately addressed by businesses. These requirements are being more strictly monitored given the current state of the global financial market and consequently the cost of satisfying these requirements have risen significantly. When CitiPower retires debt and replaces it, in order to maintain its credit rating, it must implement one of a number of options well in advance of the debt maturity date to ensure that it is not exposed to movements in capital markets at the time the debt matures and to provide assurance that the debt can be secured. Attachment C0069 is an article from Standard and Poors on refinancing and Attachment C0058 is a letter response from Standard and Poors clarifying their position. These attachments indicate that to avoid negative rating consequences a corporate would need to meet a progression of debt refinancing milestones, including that no less than three months ahead of the requirement debt refinancing would be essentially completed, committed or underwritten. The Treasury Risk Management Policy of the CHEDHA Group requires that debt funding requirements are committed, underwritten or full funded at least six months prior to the requirement for refunding.

This being the case, CitiPower has included within its forecast early debt raising costs. CitiPower has assumed that a DNSP will annually refinance one tenth of its debt three months prior to maturity, at the benchmark cost of debt, and invest the early refinanced debt in Treasury notes over those three months. CitiPower has applied the average cost of debt and Treasury note interest rate as measured over the first 15 business days in October 2009, and proposes that these values be recalculated over the measurement period proposed in Attachment C0078. For the purpose of this Regulatory Proposal, the early debt refinancing cost is calculated to be 16.6 bbpa on CitiPower's total benchmark debt.

The total debt raising costs indicated in Table 6.11 below comprise the sum of direct debt raising costs and early debt refinancing costs, which have both been calculated as set out in Attachment C0059 to this Regulatory Proposal.

	$'000 (2010)					
	2011	2012	2013	2014	2015	Total
Debt raising costs	3,991	4,257	4,396	4,458	4,485	21,587

Table 6.11: Debt raising costs 2011-15

National Framework for Distribution Network Planning and Expansion

The Australian Energy Market Commission (**AEMC**) released in September 2009 its *Final Report Review of National Framework for Electricity Distribution Network Planning and Expansion*[43] (**Final Report**). A number of recommendations arose from that Final Report, in the form of a Draft Rule Change Request, that will impact on CitiPower's operating expenditure over the next regulatory control period.

Unlike DNSPs in other jurisdictions, Victorian DNSPs have not been required to conduct regulatory investment tests. This is because Chapter 5 of the *National Electricity Rules*, and previously the *National Electricity Code*, were considered not to apply to Victorian DNSPs by the ESCV. Notwithstanding this interpretation, CitiPower has conducted a small number of regulatory investment tests for projects with a value over $10 million.

By 2011, it is expected the recommendations of the Final Report will be implemented through Chapter 5 of the Rules. This will mean that reinforcement-related (and replacement projects where they are progressing in conjunction with reinforcement projects) distribution projects with a value greater than $5 million will be subject to the regulatory investment test process. CitiPower understands that this process will require:

- a Specification Threshold Test and associated public consultation process;
- a Project Specification Report and associated public consultation process; and
- a Project Assessment Process including consideration of all applicable market benefits and costs (**RIT-D**), draft and final reports and detailed public consultation.

In addition to the regulatory investment test process, the Final Report allows for aggrieved parties to contest the process undertaken by the DNSP in completing the Project Assessment Report. The DNSP must also develop and implement a Demand Side Engagement Strategy, as well as expanded annual planning and reporting requirements.

CitiPower's experience is that the regulatory investment test process is time consuming, costly and results in it needing to obtain significant external advice to

[43] Australian Energy Market Commission, *Final Report Review of National Framework for Electricity Distribution Network Planning and Expansion*, 23 September 2009.

support its internal resources. The process has typically taken around nine months to complete and has required specialist economic and legal advice to ensure compliance with the relevant legislative requirements and the completion of the necessary modelling and calculation of benefits. Depending on the feedback from public consultation, further work may also be required in managing stakeholders and regulators. As a consequence, the average cost of the regulatory investment test process has been around $45,000. These costs would be incurred by any prudent operator in CitiPower's circumstances, ie to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.

CitiPower has reviewed its proposed capital expenditure program and identified those reinforcement projects that are likely to exceed the $5 million threshold. On the basis of these identified reinforcement projects and CitiPower's past experience regarding the costs of conducting each regulatory investment test, the additional costs detailed in Table 6.12 are expected to be incurred over the next regulatory control period.

	$'000 (2010)					
	2011	2012	2013	2014	2015	Total
Changes to planning process	633	478	604	483	522	2,720

Table 6.12: Change in costs associated with network planning 2011-15

Customer charter

Clause 9.1.2 of the *Electricity Distribution Code* requires CitiPower to provide a Customer Charter to each customer at least once every five years. The Customer Charter is required under clause 9.1.3 to summarise all current rights, entitlements and obligations of distributors and customers relating to the supply of electricity, including:

- the identity of the distributor; and
- the distributor's guaranteed service levels; and
- other aspects of the customer's relationship under the *Electricity Distribution Code* and other applicable laws and codes.

CitiPower last provided a Customer Charter to all its customers in 2006. Therefore it will next need to provide a Customer Charter in 2011.

This expenditure would be incurred by any prudent operator in CitiPower's circumstances in order to achieve the operating expenditure objective in clause 6.5.6(a)(2) of the Rules, ie to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.

The step change detailed in Table 6.13 has been calculated based on the time it would take a prudent operator in CitiPower's circumstances to develop, publish and distribute the Charter to all of CitiPower's customers.

	$'000 (2010)					
	2011	2012	2013	2014	2015	Total
Customer Charter	424	-	-	-	-	424

Table 6.13: Impact of Customer Charter 2011-15

Proposed Electricity Safety (Management) Regulations 2009

The proposed *Electricity Safety (Management) Regulations 2009* will replace the current *Electricity Safety (Management) Regulations 1999*, which are due to sunset in December 2009, as a result of the operation of section 5 of the *Subordinate Legislation Act 1994*.

To date, the *Electricity Safety Act 1998* (**Act**) and the regulations made under its authority have adopted a prescriptive approach to the regulation of the activities of DNSPs. However, Division 2 of Part 10 of the Act allows for the development, on a voluntary basis, of Electricity Safety Management Schemes (**ESMS**) by a DNSP and the approval of the ESMS by Energy Safe Victoria (**ESV**). ESV may, in the context of approving a proposed ESMS, exempt the proponent (or scheme operator) from the requirement to comply with certain aspects of Part 4 of the ESA and the relevant regulations relating to electrical installations and supply networks where appropriate. An ESMS can therefore replace strict compliance with the legislative/regulatory framework with a co-regulatory regime developed between ESV and the DNSP.

When an application for approval of an ESMS is made, ESV considers the proposed ESMS in light of requirements set out in section 111 of the Act. Once satisfied that the ESMS meets the prescribed requirements and standards, ESV must recommend to the Governor in Council that the ESMS be accepted. One aspect of the assessment of any proposed ESMS under section 111 of the Act is that the proposed scheme complies with the regulations relating to ESMS. These regulations are the *Electricity Safety (Management) Regulations 1999*.

The *Electricity Safety Amendment Act 2007*, which will come into effect on 1 January 2010, will have the effect of making it compulsory for DNSPs operating in Victoria to submit and operate under an approved ESMS. This means that the provisions of the proposed *Electricity Safety (Management) Regulations 2009* will be mandatory for DNSPs, whereas the provisions of the current regulations apply only where the DNSP has voluntarily elected to develop an ESMS.

The 2007 amendments to the Act mean that CitiPower must have an approved ESMS in place. This will effectively mean that it will need to review and revise its existing voluntary ESMS and have the revised mandatory ESMS accepted by ESV as conforming with the proposed regulations.

The ESV has stated the underlying rationale for moving to a regime of compulsory ESMS requirements is that the nature of the risk profile in this area of electrical safety is such that it is likely to be more efficient and effective to rely more heavily on process-based regulation and, as a corollary, reduce the current extent of prescriptive regulatory requirements in this area. Consistent with this rationale, the *Electricity Safety (Network Assets) Regulations 1999* will not be re-made after they sunset in December 2009.

The Regulatory Impact Statement prepared by ESV in relation to the *Electricity Safety (Management) Regulations 2009* (**RIS**)[44] indicates it expects the revised Regulations to increase the substantive costs faced by DNSPs to a significant degree. It concludes this on basis ESV expects to require more detailed and wider ranging ESMSs to be prepared under the new mandatory arrangements than have been adopted in practice under the current voluntary schemes.

The RIS does not provide any precise estimates as to the increase costs but states:

> *'…indicative estimate is that the current level of substantive costs could increase by a factor of up to 100% following the implementation of the mandatory ESMS arrangements.'*[45]

CitiPower's existing voluntary ESMS was due to expire in October 2009. It is anticipated it will be required to submit a mandatory ESMS under the new Regulations prior to the end of 2010. Uncertainty as to the contents of the mandatory ESMS and ESV's acceptance of that mandatory ESMS, mean the forecast costs are necessarily preliminary in nature. As a consequence, CitiPower has estimated the step change on the basis of 50 per cent increase on existing costs under its present voluntary ESMS. Only the operating expenditure component of the mandatory ESMS has been considered for purposes of deriving the step change.

	$'000 (2010)					
	2011	2012	2013	2014	2015	Total
Safety Management Schemes	274	272	273	275	275	1,369

Table 6.14: Proposed Electricity Safety (Management) Regulations 2009

West Melbourne demand management

As noted in Chapter 5, CitiPower already has underway substantive capital works projects that will continue over the next regulatory control period to reduce the energy risk at risk at West Melbourne Terminal Station (**WMTS**) and Richmond Terminal Station (**RTS**). WMTS is particularly important as it is facing the likelihood of peak demand exceeding its *'N'* capacity rating while suppling the Port of Melbourne, North Melbourne, Docklands and the western half of Melbourne's central business district.

Whilst through the Metro 2012 project (see Reinforcement discussion in Chapter 5), the energy at risk at West Melbourne will decline through the transfer of load to Brunswick Terminal Station, the necessary works will not be completed until late 2013. As a consequence in the interim period 2011-13 it will be necessary for

[44] Energy Safe Victoria, Regulatory Impact Statement, Electricity Safety (Management) Regulations 2009, August 2009

[45] Energy Safe Victoria, Regulatory Impact Statement, Electricity Safety (Management) Regulations 2009, August 2009, p.3

CitiPower to seek alternate arrangements to ensure the security of the network in the areas supplied by WMTS. The prudency of this action has been reinforced by advice from SP AusNet, date 14 October 2009 where the WMTS output has been reviewed following the summer of 2008-09. The advice from SP AusNet indicates that the station cyclic rating has decreased approximately 30MVA at an ambient of 35°C and at an ambient of 43°C the station cyclic rating has reduced by 53MVA from the previous cyclic rating.

As a consequence CitiPower has commenced preliminary discussions with a number of parties offering demand side management services. CitiPower intends to enter into agreements with one or more demand side management proponents on the basis they will be able to co-ordinate the curtailment of load in the area supplied by WMTS should the security of the network in that area be at risk. In return for offering this service, demand side management service providers will charge CitiPower an annual fee.

Based on discussions to date with demand side management proponents, CitiPower has developed a forecast of the fees it would be expected to incur in relation to demand side management services over the next regulatory period. These form the basis for calculating the step change.

[redacted]

Table 6.15: West Melbourne Demand Side Management Services 2011-15

6.9.4 Self insurance

Self insurance is included as a cost in CitiPower's 2009 base year operating expenditure. This section therefore explains CitiPower's forecast self insurance costs for the next regulatory control period based on the requirements in paragraphs 4.3, 4.4 and 4.5 of the RIN.

Description of the risk

Paragraph 4.3(a)(i) of the RIN requires CitiPower to describe the risk that it is self-insuring.

CitiPower's risk management philosophy with respect to insurance is to retain those exposures it can manage economically and to obtain commercial insurance for those exposures which have the potential to cause financial distress. CitiPower reviews these exposures at regular intervals.

As a result of these reviews, CitiPower resolved in 2004 to manage the following risk exposures through a Discretionary Risk Management Scheme (**DRMS**):

- uninsurable risk where commercial insurance is either unavailable or the terms prohibitive;

- excess, or deductible amounts incorporated within a commercial insurance policy; and
- damages that exceed the limits of commercial insurance policies.

CHED Services established a DRMS in 2004 to provide in-fill cover to CitiPower (amongst other clients) in respect of amounts below the policy deductibles under the following external insurance policies:

- liability insurance;
- property insurance; and
- motor vehicle insurance.

As part of this Regulatory Proposal, CitiPower has provided the AER with copies of the *Constitution CHED Services Discretionary Risk Management Scheme (***Constitution***)* and the *Discretionary Risk Management Scheme - Policy Framework* (**Policy Framework**) that explains how the Scheme is operated.

The DRMS retains funding reserves based on payments made by CitiPower (and other clients) in order to enable CHED Services to meet the cost of claims under the DRMS. Amongst other things, the Policy Framework details:

- the limits of the cover available to CitiPower under the DRMS; and
- how the contributions that are paid by members, including CitiPower, are determined.

In relation to the property insurance, for example, CitiPower can claim under the DRMS for damage to property or other assets that it owns and is legally responsible for that results in any business interruption. The limits of the property coverage are $500,000 for each and every claim or a series of claims arising out of the same event. Examples of the assets or property that are claimable under the DRMS include:

- assets within a zone substation fence, although assets that are strictly excluded from the Scheme include poles and wires and all assets outside the zone substation fence; and
- property, including depots, sheds and new buildings, including furniture, stock and fixtures within these buildings.

The typical process that occurs following damage to property or other assets is as follows:

- CitiPower undertakes the required work immediately after the event. This usually involves significant capital expenditure (and very little if any operating expenditure). This is recorded against:

- o Reliability and Quality Maintained capital expenditure for network assets; and
- o Other non-network capital expenditure for non-network assets.

  Accordingly, this expenditure is ultimately included in the RAB.

- CitiPower submits its claim forms under the DRMS to CHED Services every six months;
  - o CHED Services process the claim and reimburse CitiPower under the DRMF for the cost of the expenditure that CitiPower has incurred; and
  - o CitiPower recognises the payment as revenue item, which is netted off the capital expenditure category against which costs of the works were originally recorded.

This process therefore ensures that CitiPower does not over recover under the Scheme. A similar process applies to claims made in respect of liability and motor vehicle insurance.

Calculation of self insurance risk premium

Paragraph 4.3(a)(ii) of the RIN requires CitiPower to describe the calculation of the self insurance risk premium and to detail the premium for each regulatory year.

CitiPower commissioned Aon to quantify the risks of both the excess component of insured risks (managed through the DRMS) and the uninsurable risks faced by CitiPower over the period 2011-15. This forecast represents the amount that CitiPower could expect to pay into the DRMS during this period.

The calculation of CitiPower's self insurance risk premium is set out in Aon's report *CitiPower Self Insurance Risk Quantification*, which has been provided to the AER as an attachment to this Regulatory Proposal. The approach and methodology applied by Aon in determining its forecasts for CitiPower's self insurance premiums for the next regulatory control period are detailed in section 2.2 of Aon's report. CitiPower notes for the purposes of paragraph 4.5(c) of the RIN that it has used actual historical frequency and cost information in the calculation of each of its self insurance risk premiums.

CitiPower's self insurance for the 2009 base year has been deducted from Aon's forecasts, in order to quantify the step change in self insurance costs for the next regulatory control period. The step changes are detailed in Table 6.16.

	$'000 (2010)					
	2011	2012	2013	2014	2015	Total
Self insurance premiums step change	131	138	139	139	139	686

Table: 6.16: Step change in self insurance 2011-15

For the purposes of paragraph 4.3(a)(ii) of the RIN, Table 6.17 details CitiPower's self insurance premiums for the next regulatory control period.

	$'000 (2010)					
	2011	2012	2013	2014	2015	Total
Self insurance premiums	965	972	973	973	973	4,856

Table: 6.17: Self insurance premium 2011-15

Actuarial report

Paragraph 4.3(a)(iii) of the RIN requires CitiPower to provide a report from an actuary in relation to the self insurance premium.

As noted above, CitiPower has provided the AER with a copy of Aon's report entitled *CitiPower Self Insurance Risk Quantification*. The report includes an actuarial opinion from Aon Benfield.

External quotes

Paragraph 4.3(a)(iv) of the RIN requires CitiPower to provide any quotations obtained from external insurers in relation to the self insurance premium. No such quotations have been sought or obtained. As a result, CitiPower does not have any quotes obtained from external providers to provide the AER in response to paragraph 4.3(a)(iv) or any information in relation thereto to provide to the AER in response to paragraph 4.3(b)(ii) of the RIN.

Justification for compensation for the risk

Paragraph 4.3(b)(i) of the RIN requires CitiPower to explain why compensation should be provided for the risks covered by self insurance. Paragraph 4.3(b)(iii) of the RIN requires CitiPower to explain that the costs are not otherwise being recovered through another mechanism.

Self insurance is required for each self-insurance risk identified because:

- the costs relate to the excess component of insured risks that are managed through the DRMS; and
- CitiPower is not otherwise compensated for the costs of these risks through the economic regulatory framework. In particular, none of the following mechanisms compensate CitiPower for these costs:
    - insurance policies – self insurance covers the excess under CitiPower's policies;
    - other elements of the operating expenditure building block;
    - the capital expenditure building block;
    - cost pass-through provisions; or

   - the weighted average cost of capital and the return on capital building block.

As with insurance, self insurance is a critical element of CitiPower's approach to risk management. Having appropriate self insurance coverage ensures that CitiPower can meet the costs of unforseen events that may otherwise compromise its ability to maintain the reliability, safety or security of the network.

Self insurance for asset failure

Paragraph 4.4 of the RIN requires CitiPower to provide information in relation to self insurance for asset failure risk.

In respect of paragraph 4.4(a) of the RIN, CitiPower observes that it does not keep records of the number of failures by asset category, the historical costs for each asset failure or whether the costs were attributed to capital expenditure or operating expenditure. Section 3, and Appendix 1, of Aon's report provide details of the number and value of historic incurred losses relating to property that were retained by CitiPower and not covered by its insurer. The report shows that between 2006 and 2009 there were reported incidents totalling $1.8 million. As observed by Aon in its report, data prior to this period was unavailable or incomplete. These incidents would have resulted in CitiPower incurring both capital and operating expenditure during the current regulatory control period. The costs would have been capitalised or expensed in accordance with CitiPower's approach to capitalisation.

When loss forecasting methods are applied to this historical information, Aon has forecast that the average property losses will be $372,387 per annum. CitiPower could expect to retain these losses given the deductible of $500,000 for property in the current insurance program.

As the self insurance premium for property forecast by Aon is based on the actual historical incurred losses relating to property, CitiPower is not required to provide the explanation referred to in paragraph 4.4(b)(i) of the RIN.

CitiPower confirms that, for the purposes of paragraph 4.4(b)(ii) of the RIN, the costs of these property losses have not been reflected into its capital expenditure program, including its Reliability and Quality Maintained capital expenditure. This is because the capital expenditure program is built up, as described in Chapter 5 of this Regulatory Proposal:

- by applying a series of plans, policies, procedures and strategies; and
- having regard for historic capital expenditure.

However:

- the property losses to which the self insurance relates are for unforeseen events that are not otherwise forecast by applying the plans, policies, procedures and strategies; and

- the historic capital expenditure does not include the costs of the works for which claims have been made to, and amounts have been paid by, CHED Services under the DRMS. This is because, as discussed above, any payments made by CHED Services are netted off CitiPower's capital expenditure.

Self insurance for bushfire risk

Paragraph 4.5 of the RIN requires CitiPower to provide information in relation to self insurance for bushfire risk.

Aon's report notes that:

> *'No additional loss scenarios have been considered on the basis that CitiPower is deemed not to have an exposure to bushfire losses and has already experienced a number of historical losses that exceeded its current \$100k deductible (specific to general liability).'*

As a consequence, there is no explicit provision for bushfire risk in CitiPower's self insurance coverage.

Other risk for which self insurance is sought

Paragraph 4.5(c) of the RIN requires CitiPower to provide information prescribed therein in circumstances where CitiPower seeks self insurance for risks other than asset failure and bushfires but does not use available actual historical frequency and cost information in the calculation of the proposed self insurance premium.

By way of response, CitiPower confirms that for any risks other than asset failure and bushfires for which it seeks self insurance, the proposed self insurance premium has been calculated using available actual historical frequency and cost information. Accordingly, a response to sub-paragraphs (i) and (ii) of paragraph 4.5(c) of the RIN is not required in this Regulatory Proposal.

Board resolution to self insure

Paragraph 4.5(d) of the RIN seeks a board resolution in relation to CitiPower's self insurance.

CitiPower does not have a specific Board Resolution in relation to its self insurance in its possession, custody or control and, accordingly, has nothing to provide the AER in response to paragraph 4.5(d) of the RIN albeit, that there is specific Board Minutes that note the establishment of the DRMS and CitiPower's membership. However, to facilitate the AER's consideration of its self insurance arrangements, CitiPower has provided the AER, as part of this Regulatory Proposal, with copies of:

- the Constitution under which CHED Services established the DRMS in 2004. The Constitution outlines the principles, operation and application of the DRMS in respect to membership, claims, contributions, investment and powers of CHED Services;

- the letters that were exchanged between CitiPower and CHED Services, under which CitiPower became a member of the DRMS; and
- the Policy Framework that sets out, amongst other things, how the DRMS is administered, the cover that the Scheme provides to CitiPower and how contributions that are payable by CitiPower are determined.

6.10 Addressing RIN requirements by operating expenditure category

CitiPower notes that it has not forecast its operating expenditure on the basis of the operating expenditure categories defined in the RIN. Rather, it has applied a revealed cost approach to forecasting total operating expenditure, as described in section 6.9 of this Regulatory Proposal.

Nonetheless CitiPower sets out a breakdown of its operating expenditure forecast for the next regulatory control period by operating expenditure category in Regulatory Template 2.2 as required by the RIN. This section 6.10 of the Regulatory Proposal addresses the requirements of paragraphs 4.2 of the RIN for each operating expenditure category defined in the RIN.

6.10.1 Network operating costs

Paragraphs 4.2(a)(i) and(ii) of the RIN

Network operating costs include the operational costs associated with the operation of the distribution network including, but not restricted to, the staffing of the control centre, operational switching personnel, outage planning personnel, provision of authorised network personnel, demand forecasting, procurement, logistics and stores, IT costs directly attributable to network operation, insurance costs and land tax costs.

The aim and objective of these costs are to support the ongoing operation of CitiPower's network.

The step change associated with climate change, national framework for distribution network planning, changes to the *Electricity Safety (Management) Regulations 2009* and the West Melbourne Terminal Station demand management program are wholly or partially included in this cost category. The supporting material that demonstrates why these step changes will result in a change in costs in this operating expenditure category are presented in section 6.9.3 of this Regulatory Proposal.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the

actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

The step changes of relevance to the total operating expenditure forecast are detailed in section 6.9.3 of the Regulatory Proposal and table 6-17 in section 6.10.13 identifies those of the step changes that are of relevance to each operating expenditure category. As noted above, the step changes associated with climate change, national framework for distribution network planning, changes to the Electricity Safety (Management) Regulations 2009 and West Melbourne Terminal Station demand management program are of relevance to the network operating costs operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal is equally applicable in respect of this operating expenditure category.

Similarly, the role of the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As identified in the responses to 4.2(a)(ii) and 4.2(b)(v) of the RIN above, a number of step changes are totally or partially applicable to this operating expenditure category namely, climate change, national framework for distribution network planning, changes to the *Electricity Safety (Management) Regulations 2009* and West Melbourne Terminal Station demand management program. The process undertaken for identifying and quantifying the respective step changes, the extent to which they are recurrent in nature and the extent to which they relate to environment, safety or legal regulatory obligations or requirements are presented in section 6.9.3 of this Regulatory Proposal.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.2 Billing and revenue collection

Paragraphs 4.2(a)(i) and (ii) of the RIN

Billing and revenue collection costs include cost associated with the billing of retailers for the use of the distribution network, and the associated collection of distribution revenue from retailers. Included in this category are:

- the invoicing function;
- the accounts receivable function;
- the credit and bad debt collection function;
- the customer transfer function; and
- costs of operating the Customer Information System (**CIS**).

The aim and objective of this cost category are to collect the revenues associated with operating and maintaining the distribution network.

There are no step changes associated with this operating expenditure category.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the

actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

As noted above, there are no step changes of relevance to this operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As noted above, there are no step changes applicable to this operating expenditure category and, accordingly, no explanation is required for this operating expenditure category for the purposes of paragraph 4.2(c)(viii) of the RIN.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.3 Advertising/marketing

Paragraphs 4.2(a)(i) and (ii) of the RIN

Including in the advertising/marketing category are costs associated with providing information to customers, and conducting promotional activities, in order to improve the utilisation of the network assets by improving the power factor or the load factor.

This category also includes:

- providing contact telephone numbers for fault reporting, for example through bill inserts;
- publicising reliability targets and communicating with network customers on reliability matters;
- development of network tariffs;
- communicating with customers on distribution matters, for instance, providing notice of planned interruptions;
- educating the public on network-related electrical safety; and
- activities arising from regulatory obligations in relation to quality of supply.

The aims and objectives of this operating expenditure category are to ensure the safe and efficient use of the distribution network by customers.

There are no step changes associated with this operating expenditure category.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

As noted above, there are no step changes of relevance to this operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;

- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As noted above, there are no step changes applicable to this operating expenditure category and, accordingly, no explanation is required for this operating expenditure category for the purposes of paragraph 4.2(c)(viii) of the RIN.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.4 Customer service

Paragraphs 4.2(a)(i) and (ii) of the RIN

Customer service includes the costs of providing the following services to distribution customers:

- facilitating the reporting of network faults and safety hazards, and complaints about the quality and reliability of supply;
- responding to queries, for example from retailers, customers, builders and contractors, on new connections, disconnections and reconnections; and
- responding to queries, for example from customers, builders and contractors, on improving power factor or load factor.

This category also includes call centre costs and CIS operating costs that are directly attributable to or caused by the provision of distribution services.

The aims and objectives of this operating expenditure category are to ensure the safe and efficient use of the distribution network by customers.

This operating expenditure category includes the step change associated with the provision of a Customer Charter. The supporting material that demonstrates why this step change will result in a change in costs in this operating expenditure category is identified in section of this Regulatory Proposal.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

The step changes of relevance to the total operating expenditure forecast are detailed in section 6.9.3 of the Regulatory Proposal and Table 6-17 in section 6.10.13 below identifies those of the step changes that are of relevance to each operating expenditure category. As noted above, the step change associated with the provision of a Customer Charter is of relevance to the customer service operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.12 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As identified in the response to 4.2(a)(ii) and 4.2(b)(v) of the RIN above, the distribution of a Customer Charter step change is included in this operating expenditure category. The process undertaken for identifying and quantifying this step change, the extent to which it is recurrent in nature and the extent to which it relates to environment, safety or legal regulatory obligations or requirements are presented in section 6.9.3 of this Regulatory Proposal.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.5 Regulatory costs

Paragraphs 4.2(a)(i) and (ii) of the RIN

This cost category includes the costs of meeting economic regulatory requirements as they apply to CitiPower including:

- licence fees;
- costs associated with staffing the regulatory function covering both state and federal economic regulation;
- costs associated with providing information requested by regulatory authorities;
- costs associated with preparing submissions to regulatory authorities in response to consultation processes administered by the regulatory authorities;
- costs associated with participation in the AER's reviews of price controls and the development and implementation of standards and procedures administered by regulatory authorities; and
- costs of non-financial regulatory audits.

The aims and objectives of this operating expenditure category are to ensure the distribution network remains compliant with its economic regulatory requirements.

There are no step changes associated with this operating expenditure category.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

As noted above, there are no step changes of relevance to this operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As noted above, there are no step changes associated with this operating expenditure category and, accordingly, no explanation is required for this operating expenditure category for the purposes of paragraph 4.2(c)(viii) of the RIN.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.6 Other network operating costs

Paragraphs 4.2(a)(i) and (ii) of the RIN

Other network operating costs includes finance, human resources, information technology and other costs that are caused by the provision of distribution services.

The aims and objectives of these costs are to ensure the support for the provision of distribution services.

The step changes associated with this cost category include insurance, self insurance and debt raising costs. The supporting material that demonstrates why these step changes will result in a change in costs in this operating expenditure category is presented in section 6.9.3 of this Regulatory Proposal.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

The step changes of relevance to the total operating expenditure forecast are detailed in section 6.9.3 of the Regulatory Proposal and Table 6-17 in section 6.10.13 below identifies those of the step changes that are of relevance to each operating expenditure category. As noted above, the step changes associated with insurance, self-insurance and debt raising costs are of relevance to the other network operating costs operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.12 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As identified in the Business response to 4.2(a)(ii) of the RIN, the insurance, self insurance and debt raising step changes are included in this operating expenditure category. The process undertaken for identifying and quantifying these respective step changes, the extent to which they are recurrent in nature and the extent to which they relate to environment, safety or legal regulatory obligations or requirements are presented in section 6.9.3 and 6.9.4 of this Regulatory Proposal.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.7 SCADA and network control

Paragraphs 4.2(a)(i) and (ii) of the RIN

This operating expenditure category includes costs associated with the operation and maintenance of the supervisory control and data acquisition system and network control systems.

The aims and objectives of this operating expenditure category are to operate and communicate reliably and safely across the distribution network.

There are no step changes associated with this operating expenditure category.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the

actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

As noted above, there are no step changes of relevance to this operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As noted above, there are no step changes associated with this operating expenditure category and, accordingly, no explanation is required for this operating expenditure category for the purposes of paragraph 4.2(c)(viii) of the RIN.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.8 GSL payments

Paragraphs 4.2(a)(i) and (ii) of the RIN

This operating expenditure category includes costs associated with making guaranteed service level payments under the relevant regulatory instruments.

The aims and objectives of this operating expenditure category are to ensure the distribution network remains compliant with its economic regulatory requirements.

There are no step changes associated with this operating expenditure category.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

As noted above, there are no step changes of relevance to this operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As noted above, there are no step changes associated with this operating expenditure category and, accordingly, no explanation is required for this operating expenditure category for the purposes of paragraph 4.2(c)(viii) of the RIN.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.9 Routine maintenance

Paragraphs 4.2(a)(i) and (ii) of the RIN

These costs include as defined under the RIN, recurrent or programed asset maintenance activities undertaken regardless of the condition of the asset.

The aims and objectives of this operating expenditure category are to ensure the safe and efficient operation of the distribution network.

One step change namely, *Electricity Safety (Management) Regulations 2009* is partially included in this operating expenditure category. The supporting material that demonstrates why the step changes will result in a change in costs incurred in this operating expenditure category is presented in section 6.9.3.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

The step changes of relevance to the total operating expenditure forecast are detailed in section 6.9.3 of the Regulatory Proposal and Table 6-17 in section 6.10.13 below identifies those of the step changes that are of relevance to each operating expenditure category. As noted above, the step changes associated with changes to the *Electricity Safety (Management) Regulations 2009* is of relevance to the routine maintenance operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As identified in the response to 4.2(a)(ii) and 4.2(b)(v) of the RIN above, one step changes is partially applicable to this operating expenditure category namely, changes to the *Electricity Safety (Management) Regulations 2009*. The process undertaken for identifying and quantifying the respective step changes, the extent to which they are recurrent in nature and the extent to which they relate to environment, safety or legal regulatory obligations or requirements are presented in section 6.9.3 of this Regulatory Proposal.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.10 Condition based maintenance

Paragraphs 4.2(a)(i) and (ii) of the RIN

Costs included under this operating expenditure category, as defined under the RIN, include maintenance activities based on inspection or assessment of the condition of an asset, excluding activities that are part of a recurring maintenance program.

The aims and objectives of these costs are to ensure the safe and efficient operation of the distribution network.

There are no step changes associated with this operating expenditure category.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

As noted above, there are no step changes of relevance to this operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and

- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As noted above, there are no step changes associated with this operating expenditure category and, accordingly, no explanation is required for this operating expenditure category for the purposes of paragraph 4.2(c)(viii) of the RIN.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.11 Emergency maintenance

Paragraphs 4.2(a)(i) and (ii) of the RIN

This cost category includes, as defined under the RIN, activities that restore a failed component of the distribution network to an operational state.

The climate change step change, discussed in section 6.9.3 of this Regulatory Proposal, includes increased costs associated with this cost category, during the next regulatory control period. The supporting material that demonstrates why this step change will result in a change in costs in this operating expenditure category is presented in section 6.9.3 of this Regulatory Proposal.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

The step changes of relevance to the total operating expenditure forecast are detailed in section 6.9.3 of the Regulatory Proposal and table 6-17 in section 6.10.13 identifies those of the step changes that are of relevance to each operating expenditure category. As noted above, a portion of the step change associated with climate change is of relevance to emergency maintenance operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As identified in the Business response to 4.2(a)(ii) of the RIN, the insurance and self insurance step changes are included in this operating expenditure category. The process undertaken for identifying and quantifying these respective step changes, the extent to which they are recurrent in nature and the extent to which they relate to environment, safety or legal regulatory obligations or requirements is presented in section 6.9.3 of this Regulatory Proposal.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1 explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.12 Vegetation management

Paragraphs 4.2(a)(i) and (ii) of the RIN

This cost category includes all expenditure relating to all normal tree cutting, undergrowth control and waste disposal connected to line clearing including co-ordination and supervision of vegetation control work as defined by the RIN.

This cost category includes no step changes.

Paragraphs 4.2(b)(i)-(v) of the RIN

As discussed in section 6.9 of this Regulatory Proposal, CitiPower has adopted a revealed cost approach to forecasting operating and maintenance expenditure using 2009 as the base year. As such, it has not conducted a bottom up build of its operating and maintenance expenditure. Consistent with this, to generate forecasts by operating expenditure category, CitiPower has again, used a revealed cost approach with 2009 as the base year. The resultant forecasts by operating expenditure category reflect the actual expenditure incurred in respect of that operating expenditure category in 2009, with the addition of any step change(s) relevant to the operating expenditure category (as identified in table 6-17 below) and subject to the application of the scale and input escalators. CitiPower considers that, for the reasons of consistency, this is the only appropriate methodology for forecasting by operating expenditure category, in circumstances where the forecast operating expenditure proposal has been determined using a revealed cost approach.

It follows that, as for the forecasting of total operating expenditure using a revealed cost approach, specific policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements were not used in preparing the forecast operating expenditure for each operating expenditure category. Consequently the relevant policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements applicable to the forecasts of this operating expenditure category are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, key assumptions and relevant regulatory obligations and requirements for individual operating expenditure categories.

The relevant key assumptions for forecasting of operating expenditure and their quantum have been identified in section 6.4 of this Regulatory Proposal. The relevant regulatory obligations or requirements for the forecasting of operating expenditure are set out in section 6.5 of the Regulatory Proposal. The relevant policies, strategies and procedures for the forecasting of operating expenditure have been identified in section 6.8 of the Regulatory Proposal.

Expenditure in this cost category (with exception of the step changes) has not been subject to any consultant reports.

As for the forecast of total operating expenditure, the base year of relevance to the operating expenditure forecast for each of the operating expenditure categories is 2009.

No step changes are related to this operating expenditure category.

Paragraphs 4.2(c)(i)-(x) of the RIN

The methodology for calculating the forecasts for this operating expenditure category, and why the approach is appropriate, are outlined above in responding to paragraphs 4.2(b)(i)-(v) of the RIN.

As noted above, expenditure in this operating expenditure category (with the exception of step changes) has not been the subject of any consultant reports. As stated in section 6.8 of this Regulatory Proposal, CitiPower has not departed from any of the conclusions and recommendations made in any of the consultant reports of relevance to the forecasting of operating expenditure in preparing its forecast thereof.

It follows from the adoption of a revealed cost methodology for both forecasting of total operating expenditure and the forecasting for this operating expenditure category that the forecasts for this operating expenditure category and their preparation:

- are consistent with each of the operating expenditure criteria;
- address the operating expenditure factors; and
- achieve or meet each of the operating expenditure objectives,

for the same reasons that the forecast operating expenditure proposal and its preparation are consistent with each of the operating expenditure criteria, address the operating expenditure factors and achieve or meet the operating expenditure objectives. These reasons are set out in section 6.12 of the regulatory Proposal.

The proposed reliability targets for SAIDI, SAIFI and MAIFI have been factored into the forecast of operating expenditure for this operating expenditure category in the same way in which they have been factored into the forecast of total operating expenditure. Accordingly, the explanation of how these proposed reliability targets have been factored into the forecast of total operating expenditure, set out in section 6.7 of this Regulatory Proposal, is equally applicable in respect of this operating expenditure category.

Similarly the role the relevant network planning standards in determining expenditure under this operating expenditure category is the same as that outlined for total operating expenditure in section 6.6 of this Regulatory Proposal.

As discussed above in responding to paragraph 4.2(b)(i) and 4.2(b)(ii) of the RIN, the revealed cost methodology employed by CitiPower for forecasting total operating expenditure and the methodology used to prepare the breakdown of forecast operating expenditure by operating expenditure category mean that the relevant policies, strategies and procedures, and key assumptions, are common to the forecasting of operating expenditure for all operating expenditure categories. It is not possible or practicable for CitiPower to identify discrete policies, strategies and procedures, and key assumptions, for individual operating expenditure categories.

It follows that the way in which each policy, strategy and procedure identified in response to clause 4.2(b)(i) of the RIN was taken into account, and complied with, in respect of this operating expenditure category and the effect of any changes that were made during the current regulatory control period, are as outlined for total operating expenditure under section 6.8 of this Regulatory Proposal.

It also follows that, in respect of this operating expenditure category, the method and information used to develop the key assumptions, how the assumptions have been applied and taken into account and the effect or impact of the key assumptions in comparison to their effect or impact on actual capital expenditure are as detailed for total operating expenditure in section 6.4 of this Regulatory Proposal.

As identified in the response to 4.2(a)(ii) and 4.2(v) of the RIN above, there are no step changes related to this operating expenditure category.

As discussed above, for this operating expenditure category, as for the forecasting of total operating expenditure, the base year is 2009. Section 6.9.1explains why the base year represents efficient costs and the extent to which it includes any non-recurrent or one-off costs.

6.10.13 Operating expenditure categories and step changes

Table 6-18 details how the step changes detailed in section 6.9.3 of this Regulatory Proposal relate to each operating expenditure category.

	Climate change	Insurance	Network Planning	Customer charter	Safety Management	WMTS Demand management	Self insurance	Debt raising costs
Network operating costs	✓		✓		✓	✓		
Billing and revenue collection								
Advertising and marketing								
Customer service				✓				
Regulatory costs								
Other network operating costs		✓					✓	✓
SCADA and network control								
GSL payments								
Routine maintenance					✓			
Condition based maintenance								
Emergency maintenance	✓							
Vegetation management								

Table 6.18: Allocation of step changes to operating and maintenance expenditure categories

6.11 Operating expenditure – compliance

Clause 6.5.6(b) of the Rules requires CitiPower's operating expenditure forecasts to meet certain compliance requirements. CitiPower confirms that its operating expenditure forecasts for the next regulatory control period:

- comply with the requirements of the RIN, as required by clause 6.5.6(b)(1) of the Rules. CitiPower has provided the AER with a completed version of the Regulatory Templates at the same time as providing this Regulatory Proposal. In addition, Chapter 29 of this Regulatory Proposal provides a table that references each response to a paragraph in Schedule 1 of the RIN and explains where it is provided in, or as part of, this Regulatory Proposal;
- are for expenditure that has been allocated to Standard Control Services in accordance with CitiPower's proposed CAM, as is required by clause 6.5.6(b)(2) of the Rules;
- include the total of the forecast operating expenditure for the next regulatory control period, 2011-15, as is required by clause 6.5.6(b)(3)(i) of the Rules; and
- include the forecast operating expenditure for each year of the next regulatory control period, 2011-15, as is required by clause 6.5.6(b)(3)(ii) of the Rules.

6.12 Operating expenditure objectives, criteria and factors

Paragraph 4.2(c)(ii) of the RIN requires CitiPower to provide information about how its operating expenditure forecast relates to the operating expenditure objectives, criteria and factors in clause 6.5.6(a), (c) and (e) of the Rules.

6.12.1 Operating expenditure objectives

CitiPower considers that its forecast operating expenditure will enable it to meet the operating expenditure objectives in clause 6.5.6(a) of the Rules, so that:

- it meets or manages the demand for:
  - network services, measured in terms of maximum demand or energy consumption;
  - connection services, measured in terms of the number of new connections; and
  - unmetered supplies, measured in terms of the number of new type 7 metering installations;
- it complies with regulatory obligations that apply to its network and connection services and relevant unmetered supplies. CitiPower has assumed the current Victorian regulatory arrangements will apply unless otherwise identified; and
- its distribution system, and network and connection services and unmetered supplies, meet relevant quality, reliability, safety and security of supply standards.

CitiPower believes its operating expenditure forecast for the next regulatory control period will deliver these outcomes because:

- CitiPower is currently meeting these objectives and its forecast operating expenditure has been developed using a revealed cost approach by applying justified growth factors and step changes to the 2009 operating expenditure base year, as described in this Chapter. This means that the forecast is based on CitiPower's currently efficient operating expenditure, with necessary adjustments being made to the forecasts for growth in, and changes to the scope of, existing work;

- the nature of the activities that it will undertake through its operating expenditure program are targeted at specifically delivering the objectives. These activities are based on the practices that are currently being applied in the 2009 base year and will only change in the next regulatory control period in order to accommodate forecast growth in, and changes to, the scope of work;

- it has robust plans, policies, procedures and strategies to support the delivery of its operating expenditure program. These are based on those that are currently being applied in the 2009 base year and will only change in the next regulatory control period in order to accommodate growth in, and changes to, the scope of work; and

- it is physically able to deliver the work for the operating expenditure program by acquiring and deploying necessary labour and materials. The operating expenditure forecasts will be delivered in a similar manner to that which is currently being applied in the 2009 base year, with changes only being made in the next regulatory control period in order to accommodate growth in, and changes to, the scope of work.

6.12.2 Operating expenditure criteria

CitiPower considers that its forecast operating expenditure addresses and promotes the operating expenditure criteria in clause 6.5.6(c) of the Rules, as it reflects:

- the efficient costs of achieving the operating expenditure objectives;

- the costs that a prudent operator in CitiPower's circumstances would require to achieve the operating expenditure objectives; and

- a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

CitiPower believes its operating expenditure forecast reflects these criteria because it has applied:

- 2009 as the base year, which is efficient by virtue of CitiPower being subject to the ESCV's efficiency benefit sharing scheme as well as CitiPower's internal commercial requirements. Both of these factors provide strong incentives to pursue operating expenditure savings. At the same time, CitiPower has a clear need to ensure its operating expenditure is sufficient to meet its relevant quality, reliability, safety and security of supply obligations;

- step changes to the efficient 2009 base year in order to accommodate the different scope of work that CitiPower will need to undertake in the next regulatory control period. This means that the operating expenditure forecasts are based on CitiPower's current circumstances but have been adjusted for changes in those circumstances that it, or any prudent operator, would reasonably need to accommodate in the future;

- growth adjustments based on a realistic expectation of increased demand for network and connection services and unmetered supplies in the next regulatory control period. These adjustments reflect a realistic expectation of the increased costs that CitiPower, or any prudent operator, would reasonably need to incur in the future on account of increased growth; and

- input cost escalations, reflecting real increases in labour, material, contractor and other costs that are necessary to deliver the operating expenditure program. These cost escalations reflect a realistic expectation of the increased costs that CitiPower, or any prudent operator, would reasonably need to incur in the future in acquiring the inputs necessary to provide its services.

6.12.3 Operating expenditure factors

The operating expenditure factors in clause 6.5.6(e) of the Rules are the matters that the AER must have regard to in assessing whether CitiPower's operating expenditure forecast reasonably reflects the operating expenditure criteria in clause 6.5.6(c) of the Rules.

The operating expenditure factors in clauses 6.5.6(e)(1) to (3) of the Rules require the AER, in assessing the operating expenditure forecasts against the operating expenditure criteria, to have regard for information provided in this Regulatory Proposal, as well as submissions it receives and its own analysis. As discussed above, CitiPower considers that its operating expenditure forecasts fully reflect the operating expenditure criteria.

The operating expenditure factors in clauses 6.5.6(e)(4) to (5) of the Rules require the AER, in assessing the operating expenditure forecasts against the operating expenditure criteria, to have regard for operating expenditure benchmarks and CitiPower's actual and estimated operating expenditure in the current and previous regulatory control periods.

Regulatory Template 3.2 provides a detailed breakdown of its operating expenditure in the previous and current regulatory control periods. In addition, section 6.14 of this Regulatory Proposal provides details of CitiPower's actual and estimated operating expenditure in the current regulatory control period.

CitiPower's efficient base year costs have been calculated from the forecast regulatory accounts for 2009, consistent with CitiPower's proposed CAM. However, by 30 April 2010, CitiPower will be able to provide the AER with its audited actual operating expenditure for 2009. CitiPower expects the AER will replace the amounts included in this Regulatory Proposal with this audited actual operating expenditure for the purposes of its Draft Distribution Determination.

The operating expenditure factors in clauses 6.5.6(e)(6) and (8) of the Rules require the AER, in assessing the operating expenditure forecasts against the operating expenditure criteria, to have regard for input costs.

CitiPower has not developed its operating expenditure forecasts for the next regulatory control period by multiplying input costs and quantities. Rather, it has prepared its operating expenditure forecast based on a *'revealed cost'* methodology, which assumes that the nominated outturn year, 2009, is representative of the business's future costs. The unit costs inherent in the operating expenditure forecast are therefore based on costs historically achieved in 2009. The profile of operating expenditure in the current regulatory control period supports the view that the unit costs underlying the forecast operating expenditure are efficient. This is discussed further in Chapter 7 of this Regulatory Proposal.

Chapter 7 also provides information about the nature, and basis for, the labour, material, contractor and other cost escalators that have been applied in preparing the operating expenditure forecasts. CitiPower engaged expert consultants to forecast the real growth in the costs of each of these sub categories. The escalators determined by the expert consultants were directly applied in the development of the operating expenditure forecasts.

The operating expenditure factors in clause 6.5.6(e)(7) of the Rules require the AER to consider the substitution possibilities between operating and capital expenditure. This supports the requirement in clause S6.1.3(1) of the Rules for CitiPower to identify and explain any significant interactions between its forecast operating and capital expenditure.

There are three key aspects of CitiPower's operating and capital expenditure forecasts that present substitution possibilities, being:

- aging assets;
- investment in new systems, processes, plant and equipment; and
- purchasing or leasing new equipment or facilities.

As assets age, their condition deteriorates and maintenance costs increase, as does their risk of failure. Furthermore, the failure of aged assets presents their own risks[46]. CitiPower must evaluate whether it is more prudent and efficient to replace these assets, thereby incurring capital expenditure, or whether additional operating expenditure should be incurred to manage the risk associated with the assets. Typically, the additional operating expenditure involves more frequent and extensive condition assessments, and additional maintenance costs.

[46] Typically, older assets are more difficult to repair after failure owing to their technical obsolescence and therefore lack of availability of spare parts and/or relevant expertise and the associated (un)willingness of vendors to continue to provide support.

CitiPower's asset management plans have been prepared following Reliability Centred Maintenance (RCM) analysis and Condition Based Risk Management (**CBRM**) analysis. On this basis the operating and capital expenditure forecasts represent the optimal mix of capital asset replacement, and enhanced condition monitoring, by which to balance costs and risks of network performance.

As its commercial and operational requirements evolve, and newer technologies become available, CitiPower must evaluate whether it is prudent and efficient to invest capital expenditure in new systems, processes, plant and equipment, thereby reducing operating expenditure.

CitiPower has adopted the general principle that capital expenditure proposed for the primary purpose of delivering productivity improvements and reductions in operating expenditure should not be included in its capital expenditure proposal. If such proposals provide sufficient benefits to warrant their implementation, then the capital expenditure required will be recouped through the efficiency benefit sharing scheme.

As requirements arise that necessitate the purchase or lease of new equipment, CitiPower must evaluate whether it is prudent and efficient to make a capital investment in the purchase of new equipment, or whether the option of leasing the new equipment (and thereby incurring higher operating expenditure) is more prudent and efficient.

CitiPower's financial management processes require a financial evaluation (based on discounted cash flow analysis) to be performed whenever expenditure is proposed relating to the provision of Standard Control Services, and there are competing options available with respect to financing. As a result of these analyses, CitiPower has determined to purchase the vast majority of its vehicles, heavy equipment, property, and IT assets. The exceptions where CitiPower has elected to lease equipment typically relate to short-term requirements, or where suitable purchase options are unavailable.

CitiPower's plans, policies, procedures and strategies have regard for the interactions, and substitution possibilities, between its operating and capital expenditure programs and they are inherent in the efficient base year costs. Examples of these interactions and substitution possibilities include:

- the asset inspection program in the reliability and quality maintained capital expenditure forecast identifies whether defective assets need to be replaced by undertaking capital expenditure or alternatively whether they require condition based maintenance. Furthermore, replacing defective assets reduces the need for future maintenance as new assets are less likely to fail in service;

- reinforcement capital expenditure results in the augmentation of the distribution system and requires the newly installed assets to be operated and maintained in accordance with CitiPower's asset management policies. If inadequate augmentation work is undertaken then existing assets are more likely to fail as demand grows, which may increase the need for emergency maintenance expenditure; and

- non-network capital expenditure, such as on IT, motor vehicles, property and general equipment, are necessary enablers of the operating expenditure program and are needed to support the safe and efficient delivery of distribution services. Once they are purchased, motor vehicles and property require ongoing operating and maintenance costs.

Clause 6.5.6(e)(9) of the Rules requires the AER, in assessing the operating expenditure forecasts against the operating expenditure criteria, to have regard to the extent the operating expenditure forecast is referrable to arrangements with other parties that do not reflect arm's length terms.

As discussed in Chapter 22 of this Regulatory Proposal, CitiPower outsources a number of its functions including, its:

- field services work – these are provided to CitiPower by PNS under a Network Services Agreement; and

- back-office services, which includes its corporate services, customer services, and IT support services – these are provided to CitiPower by CHED Services under a Corporate Services Agreement.

CitiPower engaged Ernst and Young to establish the commercial benchmark for the margins applied in the Network Services Agreement and the Corporate Services Agreement.

CitiPower also engaged KPMG to quantify the efficiencies that are captured by CitiPower's service provision model relative to it providing these services in-house. KPMG, where possible, used publicly available sources of benchmarking information when estimating the efficient costs of the stand alone DNSP. KPMG found that if CitiPower had delivered its nominated services for the year ended 31 December 2008 on a standalone basis, its efficient cost of service delivery would have been $19.049 million (46 per cent)($2008) more than the costs it actually incurred for these services (excluding related party margins). In particular, in house:

- corporate and customer services would have cost $11.968 million ($2008) more than it actually incurred;

- asset management services would have cost $3.794 million ($2008) more than it actually incurred; and

- network services would have costs $3.287 million ($2008) more than it actually incurred.

The efficiency of CitiPower's service provision model is borne out in the actual efficient operating and capital expenditure performance of CitiPower over the 2006-10 regulatory control period.

Clause 6.5.6(e)(10) of the Rules requires the AER, in assessing the operating expenditure forecasts against the operating expenditure criteria, to have regard for the extent CitiPower has made provision for efficient non-network alternatives.

CitiPower has not made an explicit provision in its operating expenditure forecasts for non-network alternatives, although its efficient base year necessarily reflects network and non-network trade-offs that have been made in previous regulatory control periods. CitiPower will continue to examine the relative merits of network, and non-network, alternatives in making its future expenditure decisions. Non-network alternatives will be pursued where they provide the best solution in the circumstances to address the identified need.

6.13 Matters that are not relevant

Paragraph 4.2(c)(x) of the RIN requires CitiPower to identify why any matters referred to in paragraph 4.2 of the RIN are not relevant to its operating expenditure forecast, and to explain why this is the case.

This Chapter 6 of the Regulatory Proposal has addressed all of the matters in paragraph 4.2 of the RIN. However, because CitiPower has used a revealed cost approach, under which it has justified its total operating expenditure forecast on the basis of an efficient base year and step changes, there are some matters in paragraph 4.2 that are not directly relevant to preparing the forecast. In particular:

- CitiPower's policies, strategies and procedures, and its network planning standards and reliability targets, are not explicitly considered in preparing the operating expenditure forecasts, although they are implicit in both the efficient base year and the growth escalators that have been applied. The unit rates incurred by CitiPower meet these requirements and are inherent into the current average costs of works in the 2009 operating expenditure base year; and
- the plans, policies, procedures and strategies that are used by CitiPower to plan and conduct its day to day operations are discussed in Chapter 5 of this Regulatory Proposal and are listed and described in the completed Regulatory Template 6.4.

6.14 Historic operating expenditure

6.14.1 Variances between operating expenditure for 2001-05 and 2006-10

Operating expenditure for the previous regulatory control period and the current regulatory control period is set out in template 2.2, as required by the RIN and clause S6.1.2(7) of the Rules.

Clause S6.1.2(8) of the Rules requires CitiPower to explain any significant variations between forecast and historic operating expenditure.

The variations between operating expenditure for 2006-10 and 2001-05 are discussed in the ESCV's 2006-10 EDPR. In particular, the ESCV states that:

> '*The forecast increase* [in level of expenditure required in 2006-10 compared with 2001-05] *was due to claims by the distributors that:*

- *their rate of productivity improvements would decline and labour rates would increase;*
- *they would incur costs from servicing the forecast increase in customer numbers; and*
- *they faced numerous changes in functions and obligations for which they would incur large increases in operating and maintenance expenditure.'*[47]

The proposed variations between operating expenditure for 2006-10 and 2011-15 are discussed in section 6.9 of this Regulatory Proposal.

6.14.2 Historic and estimated operating expenditure for 2006-10

Clauses S6.1.2(7) and S6.5.6(e)(5) of the Rules require CitiPower to provide information about its actual and expected operating expenditure over the current and preceding regulatory control periods.

CitiPower has provided this information in the completed Regulatory Template 2.2.

6.14.3 Variations of historic operating expenditure from ESCV operating expenditure building blocks

Reasons for the variation

Paragraph 4.6(a)(i) of the RIN requires CitiPower to explain reasons for each of the variations in actual and estimated operating expenditure from the ESCV's operating expenditure building blocks over the current regulatory control period identified in template 5.1. CitiPower has interpreted this to mean a variation of greater than 10 per cent between the actual or estimated operating expenditure and the ESCV's operating expenditure building blocks, on the basis of template 5.1 which defines a *'significant variation'* to be a variation of more than 10 per cent.

Table 6.19 compares CitiPower's actual and estimated operating expenditure with the ESCV's regulatory allowance for the current regulatory control period.

	$'000 (real 2010)					
	2006	2007	2008	2009	2010	Total
Actual/projected	30,196	32,460	30,892	36,168	41,034	170,750
Regulatory allowance	40,369	41,666	41,834	42,690	43,544	210,103
Difference	(10,173)	(9,206)	(10,942)	(6,522)	(2,510)	(39,353)

Table 6.19: Operating expenditure over 2006-10

Accordingly, CitiPower understands there to have been a *'variation'* (for the purposes of paragraph 4.6 the RIN) in the 2006, 2007, 2008 and 2009 regulatory years.

[47] ESCV, 2006-10 EDPR, page 197

CitiPower has consistently outperformed the ESCV's operating expenditure benchmarks over the current regulatory period, a not unexpected result given the incentives CitiPower faces under the efficiency benefit sharing scheme that provides financial incentives to achieve sustained operating expenditure efficiency savings. In addition the commercial realities faced by a privatised distributor require CitiPower to continuously pursue cost efficiency savings, whilst meeting its ongoing service targets and regulatory compliance.

CitiPower's outperformance of the ESCV's operating expenditure benchmarks in the current regulatory control period was also assisted by relatively benign weather conditions over the period 2006-08 and the absence of any major unanticipated or uncontrollable costs.

The achievement of future efficiency gains will become more difficult given the gains made over the previous and current regulatory control period. CitiPower is therefore forecasting an upward trend in its operating expenditure over the next regulatory control period if it is to meet its service target and regulatory obligations.

Whether this is a recurrent or one-off variation

Paragraph 4.6(a)(ii) of the RIN requires CitiPower to explain whether the variation is recurrent or a one-off variation.

The variations over the period 2006-09 are reflective of the strong focus CitiPower management has had on pursuing efficiencies through economies of scale and scope wherever these are realisable. It was also assisted by relatively benign weather conditions over the period 2006-08 and the absence of any major unanticipated or uncontrollable costs. As discussed above, CitiPower does not anticipate that continued efficiency gains at the level achieved in the current regulatory control period will be sustainable in the next regulatory control period. Further, CitiPower has no reason to believe that the outperformance in the current regulatory control period facilitated by benign weather conditions and an absence of any unanticipated or uncontrollable costs will be sustainable in the next regulatory control period.

Factors which generally influenced variations to the ESCV approved allowance

Paragraph 4.6(a)(ii) of the RIN requires CitiPower to identify the factors which generally influenced variations to the ESCV approved allowances. As stated previously, the factors that generally influenced the variations from ESCV targets over the period 2006-08 were relatively benign weather conditions and the absence of any unanticipated or uncontrollable costs.

A number of factors have resulted in 2009 costs rising compared to the relatively constant costs over the period 2006-08. These factors are described below.

Superannuation contributions

In accordance with its legal obligations, CitiPower makes contributions to superannuation defined benefit schemes on behalf of its employees – entitlements that must be fully funded. A number of CitiPower's employees are under defined superannuation benefit schemes.

CitiPower's contribution to the defined benefit scheme has been very volatile with turbulent market conditions during the last couple of years. CitiPower made no contribution towards the scheme in 2006 or 2007.

The effects of the deteriorating market conditions, and therefore reduced value of investments related to these defined benefit schemes, have lead to an increase in the required contribution rates, particularly 2009.

The volatility in defined superannuation contributions has resulted in a variation between CitiPower's actual expenditure and the ESCV's approved allowance.

Maintenance

In 2008, CitiPower had one of its best years for average minutes off supply per customer. However in 2009, CitiPower is likely to experience one of its worst years for average minutes off supply per customer resulting in a significant step up in maintenance costs from 2008 to 2009. The poor performance in 2009 is due in part to wide scale interruptions arising from the heatwave of 29-30 January 2009.

The volatility in maintenance costs has resulted in a variation between CitiPower's actual expenditure and the ESCV's approved allowance.

EDPR 2011-15 Price Review

Every five years CitiPower is required to participate in a review of its expenditure by the AER for the purpose of establishing charges for the next regulatory control period. The costs associated with that review fall across the final three years of the regulatory control period with the majority of those costs being incurred in years four and five of the regulatory control period. 2009 is year four of the current regulatory control period.

The volatility in regulatory costs has resulted in a variation between CitiPower's actual expenditure and the ESCV's approved allowance.

6.14.4 Explanation of factors beyond CitiPower's control

Clause 4.6(b) of the RIN requires CitiPower to provide documents in support of any externally imposed variations in the current regulatory control period between its actual and estimated operating expenditure and the ESCV's building blocks that were due to factors beyond CitiPower's control. Having regard to the factors that have contributed to CitiPower's outperformance relative to the ESCV's operating expenditure benchmarks (ie: efficiency gains, benign weather conditions and an absence of unanticipated or uncontrollable costs), there are no such documents that CitiPower can provide that are responsive to paragraph 4.6(b) of the RIN.

7. UNIT COSTS AND EXPENDITURE ESCALATORS

This Chapter provides information in relation to the unit costs and escalators that CitiPower has applied in developing its capital and operating expenditure forecasts for Standard Control Services for the next regulatory control period and addresses specific requirements of the AER's RIN.

7.1 Unit costs

Paragraph 12.1 of the RIN requires CitiPower to provide information for each unit rate associated with key items of plant and equipment.

7.1.1 Capital expenditure

Paragraph 12.1(a) of the RIN requires CitiPower to identify the unit rates for key items of plant and equipment used in the estimation of its capital expenditure forecasts.

The unit rates which underpin the capital expenditure forecasts have been developed on the basis of the current average costs of undertaking similar capital works. Costs of program capital works are recorded against specific function codes and are divided by the quantity of physical units of work undertaken. The unit rates therefore represent an aggregation of materials and other costs, such as labour, that are required to complete the works. These rates do not include overheads or escalators, which are separately applied. The unit rates for key items of plant and equipment used in the estimation of CitiPower's capital expenditure forecasts are listed in the table below. They have been calculated based on average direct cost for 2009.

Activity	Unit rate ($2010)
Replace indoor air-break high voltage switch	20,361
Wood pole preservative treatment	27
Replace unserviceable pole	8,303
Reinforcement of wood pole	1,146
Underground cable joint/termination replacement	51,345
Replace cross-arm	2,586

Table 7.1: Capital expenditure unit rates (based on average current direct costs)

Paragraph 12.1(b)(i) of the RIN requires CitiPower to provide source material and evidence which demonstrates that unit rates for key items of plant and equipment reflect efficient costs.

As noted above, the source material that has been used for developing CitiPower's unit rates is the average costs of undertaking similar capital works in the current regulatory control period.

CitiPower considers that its unit rates are necessarily efficient because they are based on average actual costs of undertaking similar capital works. CitiPower notes that it engaged PB to independently review its policies, practices, procedures and governance arrangements. CitiPower has provided PB's report to the AER as an attachment to this Regulatory Proposal. PB's report found that *'the overall approach to managing network investments…..is well defined and appears to effectively control network investments'*. This supports the view that unit rates, which underpin the capital expenditure forecasts, reflect efficient costs. CitiPower's governance arrangements are detailed in Attachment C0013 to this Regulatory Proposal.

Paragraph 12.1(c)(i) of the RIN requires CitiPower to identify the date each unit rate was developed and whether the unit rates used to develop the capital expenditure forecasts are the same as those used by CitiPower for its day-to-day project and program estimation. Paragraphs 12.1(c)(ii) and 12.1(d) of the RIN require information on the areas of any difference between these unit rates.

The unit rates used to develop the capital expenditure forecasts were prepared on 30 June 2009 based on the average costs of undertaking similar capital works in the current regulatory control period. These unit rates are different to the unit rates that are used by CitiPower for its day-to-day project and program estimation. This is because:

- the unit rates that underpin the capital expenditure forecasts are based on the average costs of undertaking similar capital works in the current regulatory control period; whereas
- the unit rates that are used for day-to-day project and program estimation are dynamic in nature and are only recorded in CitiPower's internal works management system at a point in time based on applicable contract arrangements with service providers.

The differences between the two sets of unit rates therefore reflect that one set (used for the capital expenditure forecasts) is based on historic averages costs, whereas the other (used for day-to-day project and program estimation) is based on current contract arrangements with service providers.

7.1.2 Operating expenditure

As discussed in Chapter 6 of this Regulatory Proposal, CitiPower has prepared its operating expenditure forecast based on a *'revealed cost'* methodology. This assumes that the nominated outturn year, 2009, is representative of its future costs. Growth adjustments, step changes and cost escalations have then been applied to the 2009 base year in developing the operating expenditure building block.

CitiPower has therefore not developed its operating expenditure forecasts by explicitly applying unit costs. However, there are unit costs inherent in the operating expenditure forecasts, which are based on CitiPower's historic costs, ie 2009 costs. CitiPower considers that 2009 is the most efficient base year because it:

- will include the most recent year of actual outturn data. Audited regulatory accounts will be available by 30 April 2010 before the AER is required to make its Draft Distribution Determination;

- best reflects the impact of the economic conditions that are likely to prevail during the 2011-15 regulatory control period; and
- aligns CitiPower's operating expenditure forecast with the operation of the efficiency carryover mechanism that applies to it in the current regulatory control period.

For reasons of compliance with clause 12.1(b)(ii) of the RIN, presented below are CitiPower's current operating expenditure unit rates.

Activity	Unit rate ($2010)
Priority 1,2 and 3 maintenance item	260
Pole inspection	157
Switch inspection and maintenance	1,027

Table 7.2: Operating expenditure unit rates (based on average current direct costs)

7.2 Expenditure escalators

Paragraph 12.2 of the RIN requires CitiPower to provide certain information in relation to the labour and materials escalators identified in relation to its key assumptions.

CitiPower's capital and operating expenditure forecasts can be separated into the following sub-categories:

- labour – these are the costs incurred by employees and supplementary contractors in delivering Standard Control Services;
- materials – these include the costs of distribution equipment, such as transformers, circuit breakers, conductors and poles, that are used in the construction and maintenance of the distribution network. It also includes the costs of other equipment, such as vehicles, plant and tools, that is used by personnel in undertaking work on the distribution network; and
- contractor and other costs – these are the costs of other, mainly labour based, services that are purchased by CitiPower in order to deliver its Standard Control Services.

CitiPower engaged expert consultants to undertake forecasts of real growth in each of these sub-categories. The escalators determined by each of these expert consultants were directly applied to each sub-category and aggregated for each expenditure category, whether that be operating or capital expenditure.

	$'000 (2010)				
Capital expenditure	2011	2012	2013	2014	2015
Labour escalation	1,343	2,519	4,145	5,197	6,139
Material escalation	1,500	2,260	2,470	2,823	2,889
Contract and other cost escalation	2,034	4,681	7,711	10,385	12,793

Table 7.3: Net capital expenditure input escalation

	$'000 (2010)					
Operating expenditure	2010	2011	2012	2013	2014	2015
Labour escalation	462	799	1,059	1,432	1,790	2,162
Material escalation	(13)	(3)	(1)	4	4	7
Contract and other cost escalation	948	1,251	1,790	2,489	2,666	3,176

Table 7.4: Operating expenditure input escalation

7.2.1 Labour escalation

Paragraph 12.2(a) of the RIN requires CitiPower to identify the labour escalators used in the estimation of the forecast capital expenditure.

CitiPower, together with the four other Victorian DNSPs, engaged economic consultants BIS Shrapnel to forecast real wage growth for CitiPower in the next regulatory control period. A copy of BIS Shrapnel's report entitled *Wages Outlook for the Electricity Distribution Sector in Victoria*, has been provided to the AER as an attachment to this Regulatory Proposal.

In developing their forecasts, BIS Shrapnel considered both macroeconomic factors and the specific circumstances of the Victorian electricity distribution sector.

BIS Shrapnel have forecast that the strong growth in wages for the Victorian utilities sector over the current regulatory control period will continue. The key reasons given in section 4 of its report for this strong growth:

- stronger growth in demand for relevant skilled labour in Victoria over the seven years to 2015-16;
- continued high levels of utilities-related construction; and
- continued strength in enterprise bargaining agreements and individual arrangements.

BIS Shrapnel used 2009 as its base year and forecast real wages growth of 2.6 per cent per annum for the Victorian utilities sector over the five years 2011 to 2015. For the purpose of paragraph 12.2(b)(i) of the RIN, BIS Shrapnel's annual forecasts for the six years 2010 to 2015 are shown in Table 7.5.

	% (real)					
	2010	2011	2012	2013	2014	2015
Labour cost growth	3.20	2.49	2.49	2.64	2.64	2.49

Table 7.5: Forecast labour escalation

CitiPower provides the following information in relation to labour cost escalations for the purposes of paragraphs 12.2(b), 12.2(c) and 12.2(d) of the RIN:

- CitiPower:
  - cannot provide the AER with BIS Shrapnel's model that has been used to derive the labour cost escalators because model is proprietary to BIS Shrapnel and CitiPower does not have a copy of this model in its possession, custody or control. However its methodology for preparing the labour costs escalators is explained in its report to CitiPower, which has been provided to the AER;
  - did not develop a model itself to derive the labour cost escalators; and
  - developed a model to apply the labour cost escalators, which has been provided to the AER with this Regulatory Proposal.
- CitiPower has provided the AER with a copy of the current Enterprise Bargaining Agreement as an attachment to this Regulatory Proposal;
- CitiPower has split its capital and operating expenditure between labour, materials, contractor and other components. It has applied the labour cost escalator to all of its labour costs relating for both its capital and operating expenditure forecasts;
- the labour cost escalators are presented in real terms;
- the methodology that has been applied in preparing the labour cost escalators is detailed in sections 3 and 4 of BIS Shrapnel's report;
- the labour cost escalators do not involve the application of weightings. The escalators have been applied to CitiPower's un-escalated costs; and
- the same escalators have been applied to capital and operating expenditure;

Paragraph 12.3 of the RIN requires CitiPower to provide information about any negotiations to date associated with any EBA that is due to expire during the next regulatory control period. At the time of submitting this Regulatory Proposal, CitiPower has not commenced negotiations with any of the counter parties involved in establishing the next EBA.

7.2.2 Material escalation

Paragraph 12.2(a) of the RIN requires CitiPower to identify the material escalators used in the estimation of the forecast capital expenditure.

CitiPower (together with the four other Victorian DNSPs) engaged engineering consultants Sinclair Knight Merz (**SKM**) to undertake forecasts of the real escalations in the cost of materials over the next regulatory control period. A copy of SKM's report entitled *'Victorian Distribution Network Service Providers annual material cost escalators 2010-15'*, has been provided to the AER as an attachment to this Regulatory Proposal.

SKM applied the same methodology to prepare its real cost escalations that gained acceptance by the AER in several electricity regulatory and revenue proposals, including its recent Distribution Determination for the NSW DNSPs.

The methodology employed by SKM determines real price escalation for materials by considering:

- the mix of components (eg transformers, circuit breakers, etc) used by CitiPower in constructing and/or maintaining its distribution network;
- an estimate of the weighting of raw commodities influencing the cost of those components (for example the cost of transformers is influenced in varying proportions by the cost of copper, iron core material, insulating oil and structural steel); and
- the forecast real cost increases in those raw commodities.

These factors are combined in a weighted average escalator that has been applied to each capital expenditure category. For the purpose of paragraph 12.2(b)(i) of the RIN, SKM's resultant material cost escalation forecasts using the CPR5 EITE scenario are detailed in Table 7.6 below.

	% (real)					
Material cost escalator	2010	2011	2012	2013	2014	2015
Network	(1.09)	3.72	1.10	0.77	0.54	0.37
SCADA/network control	1.05	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
Non-network general IT	1.05	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
Non-network general other	1.05	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)

Table 7.6: Forecast material escalation

The forecast is reflective of commodity prices steadily recovering after the significant falls observed in 2008. From 2010 onward, real increases are broadly consistent with forecasts provided by suppliers and/or contract terms.

CitiPower provides the following information in relation to material cost escalations for the purposes of paragraphs 12.2(b), 12.2(c) and 12.2(d) of the RIN:

- CitiPower:
  - cannot provide the AER with SKM's model that has been used to derive the material cost escalators because this model is proprietary to SKM and CitiPower does not have a copy of this model in its possession, custody, or control. However the methodology for preparing the material costs escalators is explained in SKM's report to CitiPower, which has been provided to the AER;
  - did not develop a model itself to derive the material cost escalators; and
  - developed a model to apply the material cost escalators, which has been provided to the AER with this Regulatory Proposal.
- CitiPower has split its capital and operating expenditure between labour, materials, contractor and other components. It has applied the material cost escalator to all of its material related costs for both its capital and operating expenditure forecasts;
- the material cost escalators are presented in real terms;
- the methodology that has been applied in preparing the material cost escalators is detailed in section 5 of SKM's report;
- the material cost escalators do not involve the application of weightings. The escalators have been applied to CitiPower's un-escalated costs; and
- the same escalators have been applied to capital and operating expenditure.

7.2.3 Contract and other cost escalations

CitiPower uses externally contracted labour and other contracted resources for a variety of operating and capital expenditure programs and projects.

Over the past five years, CitiPower has utilised externally contracted services in areas such as: vegetation management; asset inspection; building maintenance; cleaning services; transport; traffic management; engineering consultancy; and a variety of other administrative and professional services.

Given the significant differences between the types of work classified under contracts and other costs, CitiPower (together with the four other Victorian DNSPs) engaged economic consultants BIS Shrapnel to forecast an *'Outsourced Services Wage Cost Escalator'* to be applied to these costs in the next regulatory control period. A copy of BIS Shrapnel's report entitled *Wages Outlook for the Electricity Distribution Sector in Victoria*, has been provided to the AER as an attachment to this Regulatory Proposal.

In developing their forecasts, BIS Shrapnel considered both macroeconomic factors and the specific circumstances of the Victorian outsourced services sector.

BIS Shrapnel has forecast that the strong growth in wages for the Victorian outsourced services sector over the current regulatory control period will continue. It has forecast real wages growth of 2.6 per cent per annum for the outsourced services sector over the five years 2011 to 2015. For the purpose of paragraph 12.2(b)(i) of the RIN, BIS Shrapnel's annual forecasts for the six years 2010 to 2015 are shown in Table 7.7.

	% (real)					
	2010	2011	2012	2013	2014	2015
Outsourced services escalator	3.64	1.86	2.25	2.79	2.74	2.40

Table 7.7: Forecast growth in contracts and other costs

CitiPower provides the following information in relation to contract and other cost escalations for the purposes of paragraphs 12.2(b), 12.2(c) and 12.2(d) of the RIN:

CitiPower has split its capital and operating expenditure between labour, materials, contractor and other components. It has applied the contract and other cost escalations to all of its contract and other costs relating for both its capital and operating expenditure forecasts;

- the contract and other cost escalations are presented in real terms;
- the methodology that has been applied in preparing the labour cost escalators is detailed in sections 3 and 5 of BIS Shrapnel's report;
- the contract and other cost escalations do not involve the application of weightings. The escalators have been applied to CitiPower's un-escalated costs;
- the same escalators have been applied to capital and operating expenditure;
- CitiPower:
    - cannot provide the AER with BIS Shrapnel's model that has been used to derive the contract and other cost escalations because this model is proprietary to BIS Shrapnel and CitiPower does not have a copy of this model in its possession, custody or control. However its methodology for preparing the contract and other cost escalations is explained in its report to CitiPower, which has been provided to the AER;
    - did not develop a model itself to derive the contract and other cost escalations; and
    - developed a model to apply the contract and other cost escalations, which has been provided to the AER with this Regulatory Proposal.

7.3 Contingency factors

Paragraph 12.2(d)(v) of the RIN requires CitiPower to explain whether the expenditure estimation process involves the application of any contingency factors in developing its capital and operating expenditure forecasts.

CitiPower confirms that its capital and operating expenditure forecasts for the next regulatory control period do not include any contingency factors.

7.4 Expenditure profile

Paragraph 12.2(d)(vi) of the RIN requires CitiPower to explain how the profile of expenditure for different types of projects have been developed.

7.4.1 Capital expenditure profile

Figure 7-1 shows the profile of CitiPower's capital expenditure projects for the 2011-15 regulatory control period.

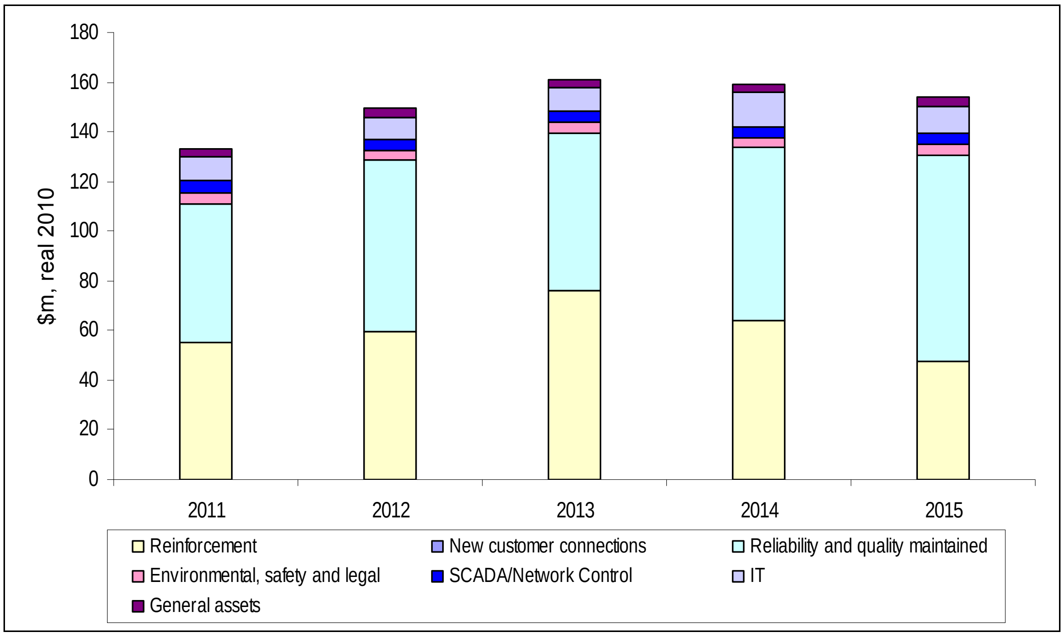

Figure 7-1 Net forecast capital expenditure - by sub-category - 2011-2015 - expenditure profile $'000 (Real 2010)

The basis on which each category of capital expenditure has been forecast is explained in Chapter 5 of this Regulatory Proposal. In summary, CitiPower has determined the required capital expenditure for each category of expenditure, except for New Customer Connection expenditure, by using a bottom up cost assessment. In the case of New Customer Connections expenditure, CitiPower has applied a *'baseline step change'* approach, as it is not feasible to apply a bottom up cost assessment to this expenditure category.

Section 5.2.12 of this Regulatory Proposal explains how CitiPower's capital expenditure forecasts for the next regulatory control period satisfy the capital expenditure objectives, criteria and factors in clause 6.5.7 of the Rules.

7.4.2 Operating expenditure profile

As discussed in Chapter 6 of this Regulatory Proposal, CitiPower has not prepared its operating expenditure forecast for the next regulatory control period based on a build up of or projects. Rather, the profile of its total operating expenditure forecast for each year of the next regulatory control period has been developed by:

- establishing an efficient 2009 base year;
- adjusting for provisions;
- removing abnormal and extraordinary items;
- removing licence fees;
- indexing the base year costs to 2010 dollars based on the Consumer Price Index;
- adding or subtracting, as relevant, changes in scope, by applying step changes;
- having regard for changes in service classification;
- applying scale escalations to each category of operating expenditure, depending on the drivers that impact them;
- applying input cost escalations, reflecting real increases in the cost of labour, material, contractor and other costs; and
- considering any interaction between operating and capital expenditure.

Figure 7-2 shows the profile of CitiPower's operating expenditure projects for the 2011-15 regulatory control period.

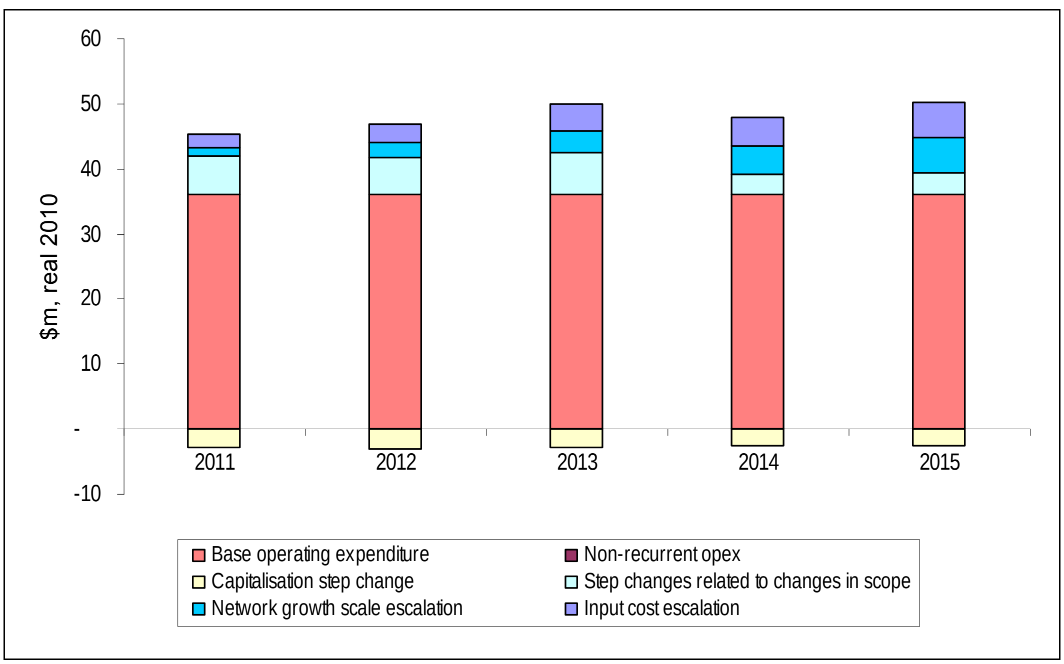

Figure 7-2: Forecast operating expenditure - 2011-15 - expenditure profile $'000 (Real 2010)

8. NON-NETWORK ALTERNATIVES

This Chapter provides information in relation to CitiPower's treatment of Non-Network Alternatives in relation to its Standard Control Services for the next regulatory control period and addresses specific requirements of the AER's RIN.

8.1 Policies, strategies, procedures for identifying non-network alternatives

Paragraph 9.1 of the RIN requires CitiPower to identify the policies, strategies and procedures, which relate to selecting efficient non-network solutions. Accordingly, CitiPower details all of its policies, strategies and procedures which relate to the selection of efficient non-network solutions below.

Currently, the *Victorian Electricity Distribution Code* requires CitiPower to:

- notify the interested parties of emerging network constraints; and
- include non-network alternatives, such as embedded generation or demand management in their planning considerations.

There are two key planning reports through which CitiPower achieves both of these requirements, which are available on CitiPower's website:

- the Transmission Connection Planning Report **(TCPR)**; and
- the Distribution System Planning Report **(DSPR)**.

These documents provide an opportunity for interested parties to express interest to CitiPower about non-network alternatives. In particular, the DSPR:

- provides a description of feasible options for meeting forecast demand and network constraints including opportunities for embedded generation and demand management where possible;
- identifies and describes the preferred options for meeting forecast demand including the estimated project cost; and
- invites proponents of non-network solutions to respond to the DSPR (refer to section 1.3 of the DSPR).

Figure 8-1 below sets out the formal process by which CitiPower identifies network constraints and identifies, assesses and ultimately implements potential solutions, including non-network solutions to addressing these constraints.

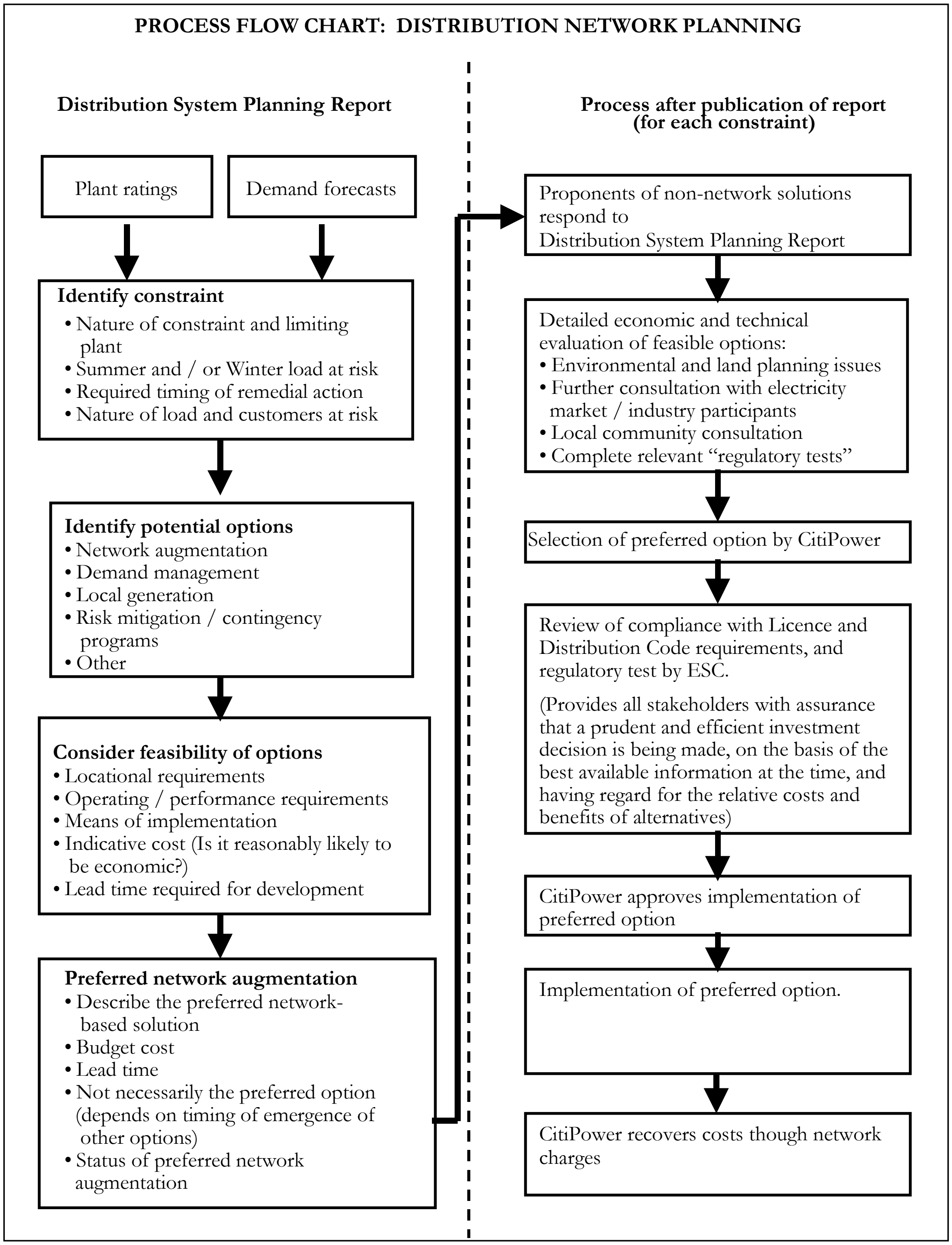

Figure 8-1: CitiPower's – Asset Management Process Model

Figure 8-2 below overviews, at a more detailed flowchart level, the process currently used by CitiPower to develop and implement non-network solutions. This process supports and expands on CitiPower's Asset Management Process Model detailed in Figure 8-1 above.

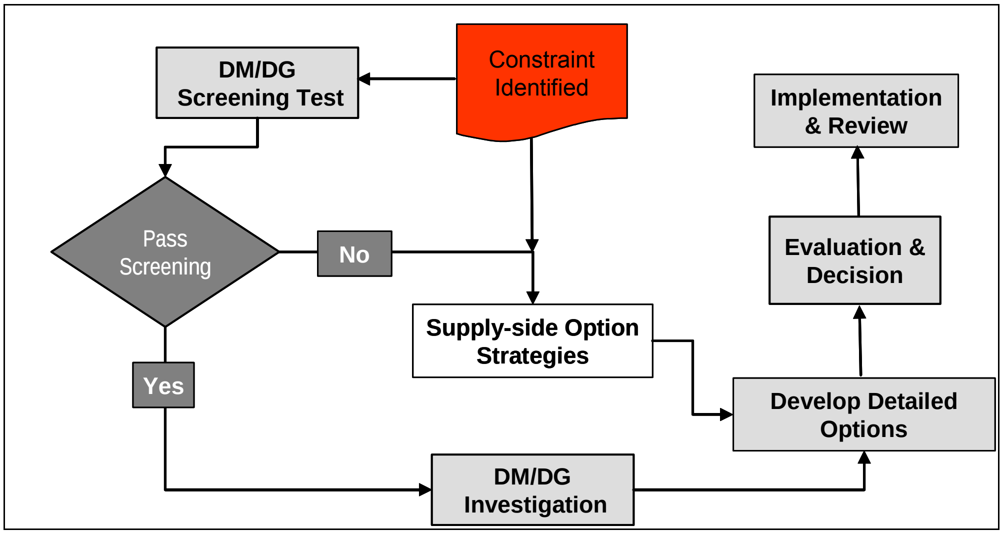

Figure 8-2 CitiPower's approach for identifying and implementing non-network solutions

Broadly, the steps currently utilised in this non-network planning and implementation process include:

- desktop screening analysis to identify potential locations and candidate projects;
- detailed analysis of impacts and costs/benefits of these short listed locations;
- business case (if appropriate given results of the previous step);
- detailed program design and implementation planning;
- project implementation; and
- monitoring and evaluation (post implementation, to ensure actual results are meeting targets and to take corrective actions as required).

In conjunction with this network planning and approval process, CitiPower also, in accordance with the requirements of clause 5.6.2(f) and (g) of the Rules, applies and consults on, Regulatory Tests for *'large'* distribution network assets which are defined as requiring expenditure in excess of $10 million. The Regulatory Test involves undertaking an economic cost effectiveness analysis of possible project options including non-network solutions, to address specific network limitations, and assists in determining whether a suitable non-network alternative is more prudent than a network augmentation.

CitiPower also has an internal business unit committed to continually reviewing emerging and innovative technologies through participation in the Energy Network Association committee on Embedded Generation and Demand Management, and the Australian Demand Management Forum which has been formed to share knowledge across the industry on the trialling of new technologies. CitiPower also monitors national and international research of non-network programs through its involvement in CIGRE[48] and the Distribution Systems and Dispersed Generation committee.

CitiPower recognises that the Australian Energy Markets Commission (**AEMC**) is currently undertaking a review of the current electricity distribution network planning and expansion arrangements including the Regulatory Test arrangements. In particular, the AEMC is, amongst other things, considering:

- the scope and objective of annual planning arrangements;
- the content of the annual planning report; and
- replacing the existing Regulatory Test with a Regulatory Investment Test – Distribution (**RIT-D**).

These recommendations will have a direct impact on CitiPower and are discussed further, as an operating expenditure scope change, in Chapter 6 of this Regulatory Proposal.

8.2 Non-network alternative capital and operating expenditure forecasts

8.2.1 Non-Network Alternatives in Next Regulatory Control Period

Paragraph 9.2(a) of the RIN requires CitiPower to detail the extent to which it has considered and made provision for efficient non-network alternatives in developing its capital and operating expenditure forecasts for the next regulatory control period. In this regard, it is noted that clauses 6.5.7(e)(10) and 6.5.6(e)(10) of the Rules require that, in assessing the capital and operating expenditure forecasts for the next regulatory control period, the AER must have regard for the extent CitiPower has considered, and made provision for, efficient non-network alternatives.

The AER's proposed Demand Management Incentive Scheme (**DMIS**) is a key mechanism through which CitiPower will consider, and make provision for, efficient non-network alternatives in the next regulatory control period. CitiPower supports the application of both parts of the proposed DMIS:

- the demand management innovation allowance (**DMIA**) – the AER has provided a DMIA of $1 million over the next regulatory control period. CitiPower has reflected this into its operating expenditure forecasts; and
- a provision for the recovery of foregone revenue as a result of reduced energy sales arising from the implementation of non-tariff demand management projects and programs approved under the DMIA. The foregone revenue will be provided in the subsequent regulatory control period.

[48] CIGRE is an International Council on Electric Systems and is a leading worldwide Organizations on Electric Power Systems

CitiPower:

- supports the implementation of demand management and/or non-network initiatives where it considers that they are more economically efficient than network augmentation;
- has developed a network planning process to identify and implement demand management alternatives where they are economically efficient; and
- has implemented various demand management and/or non-network initiatives during the current regulatory control period where they have been assessed as feasible and deliver net benefits to customers.

CitiPower's non-network alternatives program for the next regulatory control period is set in Table 6.15. This expenditure relates to the continuation of investigations of demand management options for the area supplied by West Melbourne Terminal Station **(WMTS)** which is reaching its limit due to the increased load in the CBD.

CitiPower has not made any further explicit provisions for non-network alternatives in developing its forecast expenditure for the 2011-15 regulatory control period. This is because currently CitiPower is not assessing any additional specific demand management and/or non-network initiatives. In accordance with its planning process and the Regulatory Test detailed above, CitiPower will conduct further assessment and investigations of options, including network and non-network, for specific network constraints closer to the proposed project implementation dates. The extent to which non-network and demand management options are considered within the regulatory control period will depend largely on:

- CitiPower receiving expressions of interest from proponents of feasible and economically efficient non-network and demand management initiatives; and
- advances in technology which may lead to a greater number of viable and feasible non-network and demand management opportunities arising.

8.2.2 Non-network alternatives in current regulatory control period

Paragraph 9.2(b) of the RIN requires CitiPower to explain how expenditure allocated to demand management or other non-network alternatives in the current regulatory control period under the ESCV's 2006-10 EDPR has been spent.

CitiPower reports annually to the ESCV on the demand side activities that it has undertaken each year. This report addresses the compliance requirement under section 12.8.3 of Volume 1 of the 2006-10 EDPR, which states that:

> *'…the Commission has allowed specific provision for demand management initiatives of $0.6 million for each distributor. This provision will provide additional revenue for the trial of demand management initiatives during the 2006-10 regulatory period. The Commission will require distributors to*

> *report on an annual basis the demand side activities that have been undertaken and the outcomes that have been delivered.'*[49]

CitiPower has submitted reports to the ESCV for the 2006 and 2007 years of this current regulatory proposal. These have been provided as attachments to this Regulatory Proposal. At the time of drafting this Regulatory Proposal, CitiPower was preparing its 2008 report. CitiPower will provide its 2008 report to the AER when it has been completed.

The ESCV's 2006-10 EDPR did not allocate any expenditure to demand management or other non-network alternatives in the current regulatory control period, other than the $0.6 million for each DNSP for demand management initiatives referred to above.

8.3 Non-network projects

8.3.1 Non-network projects in current regulatory control period

Paragraph 9.3(a) of the RIN requires CitiPower to identify each non-network project that has been selected during the current regulatory control period. Paragraph 9.4 of the RIN requires CitiPower to provide a description, including with respect to cost and timing, of each project.

During the currently regulatory control period CitiPower has not implemented any non-network solutions, however it is currently investigating demand management options for the area supplied by the WMTS. The capacity at the WMTS is reaching its limits due to the increased load in the Melbourne CBD. While the Metro 2012 project will address the energy at risk at the WMTS by transferring the load to Brunswick Terminal Station, the necessary works will not be completed until 2013.

Accordingly, CitiPower is currently involved in preliminary discussions with a number of parties offering demand side management services. CitiPower intends to enter into agreements with one or more demand side management proponents on the basis that they will be able to co-ordinate the curtailment of load in the area supplied by WMTS should the security of the network in that area be at risk.

8.3.2 Non-network projects in next regulatory control period

Paragraph 9.3(b) of the RIN requires CitiPower to identify its non-network projects during the next regulatory control period. Paragraph 9.4 of the RIN requires CitiPower to provide a description, including with respect to cost and timing, of each project.

As discussed in section 8.2.1 above, CitiPower has included in this Regulatory Proposal $8.4 million[50] of expenditure on non-network alternatives for the next regulatory control period. This relates to the continuation of investigations of demand management options for the area supplied by WMTS.

[49] ESCV, 2005 Pricing Determination, page 496
[50] This is the direct cost and therefore is not inclusive of cost escalations

No other non-network alternatives have been identified for the forthcoming regulatory control period at this time. CitiPower will assess the relative merits of other non-network alternatives in the course of the 2011-15 regulatory control period in accordance with its planning process and the requirements of the Regulatory Test. Accordingly, CitiPower is unable to provide a description of these alternatives in this Regulatory Proposal.

8.4 Deferred capital expenditure

Paragraph 9.5(a) of the RIN requires CitiPower to provide information on capital expenditure that it has deferred during the current regulatory control period due to the implementation of a non-network solution.

CitiPower has no deferred capital during the current regulatory control period on the basis that it has not implemented any non-network solutions.

9. EFFICIENCY BENEFIT SHARING SCHEME

This Chapter details CitiPower's proposed application of the efficiency benefit sharing scheme (**EBSS**) for Standard Control Services in the next regulatory control period and the calculation of carryover amounts for the period 2006-10.

Clause 6.4.3(a) of the Rules provides that CitiPower's annual revenue requirement for each regulatory year of the next regulatory control period must be calculated using a building block approach.

Clause 6.4.3(a)(5) of the Rules provides that one of the building blocks to be used in this approach is to be a revenue increment or decrement (if any) for the regulatory year arising from the application of the EBSS. This increment or decrement is to be calculated in accordance with clause 6.4.3(b)(5) of the Rules.

Clause 6.4.3(a)(6) of the Rules provides that one of the building blocks is the revenue increments or decrements (if any) for the regulatory year *'arising from the application of a control mechanism in the previous regulatory control period'*. The intention of this provision is to allow the AER to carry over efficiency gains or losses from the 2006-10 period when making its determination for the next regulatory control period. This increment or decrement is to be carried forward to the next regulatory control period in accordance with clause 6.4.3(b)(6) of the Rules.

In June 2008, the AER issued an EBSS in accordance with clause 6.5.8(a) of the Rules. The details of the EBSS are set out in the AER's guideline entitled *Electricity Distribution Network Service Provider Efficiency Benefit Sharing Scheme* (**Guideline**). The AER's likely approach in its Framework and Approach Paper was that it would apply the EBSS to CitiPower in the next regulatory control period. On page 112 of the Framework and Approach Paper, the AER also stated it considers that:

> *'for efficiency gains/losses realised in the current 2006/2010 regulatory control period, each annual carryover amount under the efficiency carryover mechanism will be calculated and used in the building block determination for the next regulatory control period, 2011-2015. The AER will incorporate all carryover amounts accrued in any year of the current regulatory period into forecast opex amounts for the next regulatory control period.'*

9.1 Description of how EBSS will apply

CitiPower has been subject to a similar mechanism to the EBSS in the current regulatory control period. The ESCV's 2006-10 EDPR included an efficiency carryover mechanism that involves calculating a reduction (or increase) in recurrent operating expenditure compared to forecast operating expenditure for the year. Recurrent, in this sense, means the underspend (or overspend) between the forecast and actual operating expenditure in year one, then the incremental underspend (overspend) in subsequent years[51].

[51] ESCV, Electricity Distribution Price Review, Final Decision Volume 1, October 2006, p 431.

The ESCV's efficiency carryover mechanism excludes capital expenditure.

Clause S6.1.3(3) of the Rules requires CitiPower to describe and explain how it considers the EBSS should apply to it in the next regulatory control period.

CitiPower considers that the EBSS should apply in accordance with the AER's Guideline and the AER's indicative position in its Framework and Approach Paper, but that it should incorporate the matters addressed in this Chapter in response to paragraph 10 of the RIN.

9.2 Approach to capitalisation

Paragraphs 10.1(a)(i), 10.1(b)(i)-(ii) and 10.3 of the RIN require CitiPower to provide information in relation to any changes in its capitalisation policy.

CitiPower confirms that it has not changed its capitalisation policy in either the previous or current regulatory control period. Consideration is currently being given to the alignment of CitiPower and Powercor Australia's capitalisation policies from 2011.

In response to paragraph 10.1(b)(ii) of the RIN, CitiPower advises it capitalises a portion of its corporate costs. The amount capitalised is based on a percentage of the direct costs. Further, no costs were removed from capital expenditure and included as operating expenditure.

While paragraph 10.1(b)(i) of the RIN refers to paragraph 10.1(a) in its entirety, CitiPower presumes that the reference to *'changes'* in paragraph 10.1(b)(i) is intended to refer to the change(s) made to its capitalisation policy identified in response to paragraph 10.1(a)(i) of the RIN. It follows that CitiPower has no information to provide in response to paragraph 10.1(b) of the RIN. Similarly, as CitiPower has not made any changes to its capitalisation policy, CitiPower also has no information to provide in response to paragraph 10.3 of the RIN.

9.3 Excluded cost categories

Paragraph 10.1(a)(ii) of the RIN requires CitiPower to identify all cost categories that it proposes be excluded for the operation of the EBSS.

The AER's Guideline excludes from the operation of the EBSS the cost of recognised pass-through events as well as operating expenditure in relation to non-network alternatives. In addition, CitiPower proposes to exclude guaranteed service level payments, superannuation contributions and debt raising costs on the basis they are outside the control of the Business, have proven to be relatively volatile, and their exclusion would not adversely impact the operation of the EBSS.

Aside from these cost categories, CitiPower does not propose any further adjustments for uncontrollable costs in the next regulatory control period.

However, in Chapter 12 of this Regulatory Proposal, CitiPower has nominated that a series of events be treated as pass-through events in the next regulatory control period.

If the AER does not agree to treat each of these events as pass-through events then CitiPower proposes that costs related to any of these events that are not accepted as pass-through events be treated as uncontrollable costs for the purpose of the EBSS.

These proposed pass-through events relate to the following cost categories:

- costs arising from a transfer of non-pricing distribution regulatory arrangements to a national regulatory framework;
- costs arising from changes in safety regulations introduced by the ESCV;
- costs arising from changes in exposure limits introduced in the final version of the current Draft Radiation Protection Standard for Exposure Limits to Electric and Magnetic Fields 0 Hz - 3 kHz, by the Australian Radiation Protection and Nuclear Safety Agency (ARPANSA);
- costs arising from general nominated pass through event;
- costs arising from a financial failure of a retailer event;
- costs arising from a declared retailer of last resort event;
- fees or charges payable to the Australian Energy Market Operator (**AEMO**); and
- costs arising from an emissions trading scheme event.

The reasons why each of these cost categories are uncontrollable are set out in Chapter 12 of this Regulatory Proposal. None of these cost categories is controllable by CitiPower and their exclusion would not impact the operation of the EBSS.

9.4 Proposed base year

Paragraph 10.1(a)(iii) of the RIN requires CitiPower to identify the proposed EBSS base year.

CitiPower proposes that this base year be 2009.

For the purpose of paragraph 10.1(b)(iii) of the RIN, an explanation of how 2009 represents an efficient base year is provided in section 6.8.1 of this Proposal.

9.5 Carryover period

CitiPower proposes that a carryover period of five years apply to the EBSS, as provided for in clause 2.3.3 of the EBSS Guidelines.

9.6 Calculation of carryover amounts

9.6.1 RIN requirements regarding calculation of carryover amounts

Paragraphs 10.1(a)(iv)-(v) and 10.2 of the RIN require CitiPower to calculate and provide information about the carryover amounts accrued under the ESCV's efficiency carryover mechanism for each year of the current regulatory control period.

CitiPower's outturn operating expenditure for the current regulatory control period is calculated as discussed in section 1.2 and Chapter 6 of this Regulatory Proposal and is set out in Table 9-1. These calculations are consistent with the requirements of the ESCV's *Electricity Industry Guideline No. 3* and CitiPower's proposed CAM.

CitiPower's operating expenditure benchmarks from the current regulatory control period are set out in Table 9-1. These benchmarks are taken from 2006-10 EDPR.

CitiPower has then calculated the carryover amounts for each regulatory year of the current regulatory control period in accordance with paragraphs 10.1(a)(iv) and 10.1(a)(v) of the RIN. In doing so, CitiPower has made the adjustments detailed in this section 9.6.

CitiPower has interpreted the requirements of paragraphs 10.1(a)(iv), 10.1(a)(v) and 10.2 of the RIN as follows:

- paragraph 10.1(a)(iv) requires that, when calculating the carryover amounts for the current regulatory period, CitiPower must make adjustments to its outturn operating expenditure and/or the operating expenditure benchmarks in accordance with:

    (1) the growth adjustment formula in the 2006-10 EDPR; and

    (2) the principles on changes to capitalisation policy contained in the 2006-10 EDPR;

- paragraph 10.1(a)(v) provides that when calculating the carryover amounts CitiPower must also identify any carryover amounts that have not been calculated in accordance with paragraphs 10.1(a)(iv)(1) and (2), which CitiPower interprets as expressly permitting it to also make other adjustments to its outturn operating expenditure and/or operating expenditure benchmarks that are not referred to in paragraphs 10.1(a)(iv)(1) and (2); and

- paragraph 10.2 appears to contain a cross-reference error, when it requires CitiPower to explain in relation to the carryover amounts identified in response to paragraph 10.1(a)(iv) *'why the alternative calculation methodology was used'*. CitiPower assumes that it is intended to require CitiPower to explain why the other adjustments that are permitted by paragraph 10.1(a)(v) were made.

In summary, CitiPower therefore interprets paragraph 10.1(a)(iv) as requiring CitiPower to make the adjustments referred to in that paragraph when calculating the carryover amounts, and interprets paragraph 10.1(a)(v) as also expressly permitting

CitiPower to make other adjustments when calculating the carryover amounts, provided that CitiPower provides the information required by paragraph 10.2.

9.6.2 Adjustments to account for growth and changes to capitalisation policies

In accordance with paragraph 10.1(a)(iv) of the RIN and the ESCV's efficiency carryover mechanism in the 2006-10 EDPR, CitiPower has adjusted the 2006-10 operating expenditure benchmarks for the difference between forecast and actual growth. It was unnecessary to adjust the 2006-10 operating expenditure benchmarks in accordance with the principles on changes to capitalisation policy contained in the EDPR because there have not been any changes to CitiPower's capitalisation policy during the current regulatory control period.

9.6.3 Other adjustments to account for unforeseen and uncontrollable changes in the scale and scope of CitiPower's activities

As permitted by paragraph 10.1(a)(v) of the RIN, CitiPower has also made adjustments to its actual operating expenditure for the purposes of the efficiency carryover calculation.

These adjustments are required in order to account for unforeseen and uncontrollable changes in the scale and scope of the activities that CitiPower is required to undertake in order to provide its distribution services, and to allow a like-for-like comparison with the operating expenditure forecasts that were set by the ESCV in the 2006-10 EDPR and the scale and scope of activities that the ESCV assumed would be required when setting those forecasts.

The adjustments are consistent with:

- the approach taken by the ESCV in the 2006-10 EDPR;
- the decision of the Appeal Panel in 2000 in CitiPower's successful appeal of the 2001-2005 EDPR in relation to the ORG's refusal to make certain adjustments; [52] and
- the AER's Guideline, which provides for adjustments to exclude pass-through events and other nominated uncontrollable costs from the application of the EBSS.

In the appeal of the 2001-05 EDPR, the Appeal Panel rejected the ORG's decision not to make adjustments to actual 1995-99 costs for the purposes of the efficiency carryover mechanism. The Appeal Panel held that the ORG must reconsider its determination to:

- *'ensure that the approach is as consistent as is feasible, given the available information, with the benchmark forecasts of expenditure'*; and

[52] *Statement of Reasons for Decision by Appeal Panel in the matter of the Office of Regulator-General Act 1994 and in the matter of an appeal pursuant to s.37 of the Act brought by Powercor Australia Limited, 30 October 2000.*

- '*incorporate the effects on costs of the differences between forecast and actual demand in the measure of efficiency carry over'*.

The Appeal Panel also made the following comments showing the need for the original forecasts from 1995 to be consistent with the basis and coverage of the actual expenditure figures for 1999 and the need to make adjustments for changes to the scope and size of CitiPower's operations:

> *'The Panel considers that to obtain a measure of efficiency for the purposes of incorporation in the efficiency carry over mechanism, it is necessary that accounts which are being compared are produced on a comparable basis,*
>
> *and that these accounts cover a comparable range of operations.*
>
> *...*
>
> *It follows that the basis and coverage of the actual 1999 accounts should be the same as the basis and coverage of the 1999 benchmark forecast accounts. Unless this is the case, any indicators derived will not measure what they purport to measure.*
>
> *...*
>
> *The Panel notes that the Office measures efficiency by comparing actual total costs (including operating and maintenance costs, and capital costs) as achieved in 1999 with the benchmark forecasts, for the distribution business, for that year. The Panel recognised that this comparison does not make any allowance for changes in the size or scope of the business from those which were assumed in the benchmark forecast.*
>
> *In the Panel's view this results in a measure, which does not reflect efficiency as normally understood, and which creates incentives for the distribution business to perform inefficiently.*
>
> *...*
>
> *The efficiency measure, as adopted by the Office in the rule of thumb, is inconsistent with the Office's objectives for the efficiency carry over as enunciated on p83 of the Determination to the extent that it fails to scale for cost carry over changes as a result of changes in size and scope of operations. It was emphasised by counsel for the office that these objectives were to apply to the transitional mechanism.*
>
> *...*
>
> *The Panel decided that the use of a rule of thumb to measure efficiency which did not make allowance for changes in scale and scope of the business constituted an error of fact in a material respect.'*

In the 2006-10 EDPR, the ESCV adopted the Appeal's Panel's approach and broadened it to develop a general principle that adjustments must be made to allow a *'like-for-like comparison'* between forecast and actual expenditure for the efficiency carryover calculation. For example, the ESCV stated:

'To calculate the efficiency carryover amounts that give effect to this sharing, the Commission must also be able to compare the out-turn costs during the 2001-05 regulatory period to the benchmark expenditure requirements established for the 2001-05 regulatory period. This requires the Commission to understand the basis on which the distributors' out-turn costs have been calculated so that it is possible to compare out-turn costs on a like-for-like basis with the appropriate benchmarks.[53]

...

For the rewards implicit in the efficiency carryover to reflect the cost of providing the distribution services, it is important that the reported expenditure information is calculated on the same basis as the expenditure forecasts against which it is compared. Therefore, for the purpose of calculating the efficiency carryover amounts from the 2001-05 regulatory period, the Commission has adjusted either the reported expenditure or the original benchmarks of all the distributors to ensure consistency between the basis on which the 2001-05 benchmarks were estimated and the costs incurred in providing distribution services.[54]

...

In the Commission's view, this approach is entirely consistent with the findings of the Appeal Panel which outlined the importance of measuring efficiency on a like-for-like basis and consistently across distributors. For example, the Appeal Panel stated that:

- *to obtain a measure of efficiency for the purposes of incorporation in the efficiency carryover mechanism, it is necessary that accounts which are being compared are produced on a comparable basis, and that these accounts cover a comparable range of operations;*

- *where actual amounts include or exclude items that are included in benchmarks, this is a serious problem which limits the accuracy of measuring efficiency[.]'*[55]

This approach is also consistent with the fact that the AER's Guideline provides for the making of adjustments to actual and forecast operating expenditure for 2011-15 and future periods. In particular, the Guideline provides that pass though events will be excluded from the efficiency carryover calculation and that a DNSP can propose a range of additional *'uncontrollable'* cost categories for exclusion from the operation of the EBSS. If an increase in expenditure arises from an event that would be a pass-through event (as defined in the Rules) and would be excluded from the EBSS under the AER's Guideline had it occurred during 2011-2015 rather than 2006-10, then the same approach should apply to the carryover of 2006-10 gains or losses and an adjustment should be made to 2006-10 actual operating expenditure to exclude the effects of that event.

[53] EDPR 2006-10, page 159.
[54] EDPR 2006-10, page 419.
[55] EDPR 2006-10, page 419.

These adjustments under the Guideline can be seen as a particular application of the principle laid down by the Appeal Panel and the ESCV that adjustments must be made so that a like-for-like comparison can be made between the forecast and actual operating expenditure and a DNSP is not treated as being *'inefficient'* merely because unforeseen and uncontrollable events required it to carry out additional activities that were not contemplated when the original forecasts were prepared.

As a result of applying these principles, CitiPower has made adjustments to the following costs when calculating the efficiency carryover amounts for the period 2006-10:

- superannuation costs incurred between 2006 and 2009 have varied significantly due to sharemarket volatility over the current regulatory period. Such volatility was not envisaged at the last regulatory review. As a consequence, CitiPower has adjusted benchmark operating expenditure for the purposes of the efficiency carryover calculation to superannuation expenditure over the 2006-10 regulatory control period as reported in the regulatory accounts. This adjustment is appropriate because:

    - these costs are uncontrollable and were not foreseen when the 2006-10 forecasts were prepared, and those forecasts assumed that superannuation costs would be consistent in each year of the current regulatory control period;

    - a like-for-like comparison between actual and forecast expenditure is not possible unless these costs are adjusted in the manner proposed by CitiPower; and

    - in the NSW Final Determination, the AER accepted that *'superannuation costs related to defined benefit and retirement schemes'* were an uncontrollable cost that should be excluded for the purposes of the EBSS. A consistent approach should be applied to the treatment of these costs for the 2006-10 period and CitiPower should be able to make adjustments to reflect the uncontrollable nature of these costs;

- payment of guaranteed service level (**GSL**) payments to customers. CitiPower has adjusted benchmark operating expenditure for the purposes of the efficiency carryover calculation with actual GSL expenditure over the 2006-10 period as reported in the regulatory accounts. This adjustment is appropriate because:

    - these costs are uncontrollable and were not foreseen when the 2006-10 forecasts were prepared, and those forecasts assumed that GSL costs would be consistent in each year of the current regulatory control period. CitiPower has experienced, particularly over 2009, the most difficult conditions in terms of climate related impacts on its network in its history;

    - a like-for-like comparison between actual and forecast expenditure is not possible unless these costs are adjusted in the manner proposed by CitiPower; and

- o CitiPower proposes in section 9.3 above to exclude GSL payments from the EBSS for 2011-2015 on the basis that they are uncontrollable. A consistent approach should be applied to the treatment of these costs for the 2006-10 period and CitiPower should be able to make adjustments to reflect the uncontrollable nature of these costs.

These adjustments are also supported by the objectives of the EBSS and the matters that the AER is required to have regard to under clause 6.5.8(c) of the Rules. The purpose of the EBSS is to provide DNSPs with a continuous incentive to improve efficiency and reduce operating expenditure. If the calculation of the efficiency carryover amounts does not include adjustments to address the effect of unforeseen and uncontrollable changes in the scope and scale of the activities that CitiPower is required to undertake in order to provide its distribution services, then it is not an effective measure of efficiency and does not provide effective incentives to reduce operating expenditure.

Without adjustments, a DNSP would be deemed to be inefficient merely because its legal obligations increased and it was required to increase its expenditure in order to comply with those obligations. Such an outcome would, in the words of the Appeal Panel, *'[result] in a measure, which does not reflect efficiency as normally understood, and which creates incentives for the distribution business to perform inefficiently'* and, in the words of the ESCV, it would be *'a serious problem which limits the accuracy of measuring efficiency'*.

The amounts of each of these adjustments and the adjustments in section 9.6.2 above are set out in Attachment C0062. The attachment also sets out CitiPower's proposed calculation of the efficiency carryover amounts.

Table 9-1 sets out CitiPower's calculation of the carryover amounts based on the adjustments discussed in this section 9.6.

9.6.4 Adjustments to remove ESCV efficiency adjustments

As permitted under paragraph 10.1(a)(v) of the RIN, CitiPower has adjusted its operating expenditure benchmarks for the purposes of the EBSS calculation to ensure consistency between the efficiency carryover mechanism of the ESCV and the AER's EBSS.

The ESCV's efficiency carryover mechanism differs from the EBSS developed by the AER in that it:

- established benchmarks for the current regulatory control period that required DNSP's to generate a certain level of efficiency gains before they would become eligible for any sharing of further gains and losses;
- did not provide for any uncontrollable elements of operating expenditure to be excluded from its efficiency sharing arrangements; and
- established operating expenditure benchmarks for the current regulatory control period that did not align with the actual operating expenditure in the base year.

CitiPower does not consider that it is appropriate or consistent with clause 6.5.8 of the Rules or section 7A(3) of the NEL to carry over efficiency gains and losses from the 2006-2010 regulatory period unless adjustments are made in relation to each of these matters so that the carryover amounts are calculated in a manner that is consistent with the AER's EBSS.

Section 9.6.3 of the Regulatory Proposal discusses the approach to managing uncontrollable costs. The points with respect to the establishment of operating expenditure benchmarks are discussed further below.

The consequence of incorporating forecast or target efficiency gains into a DNSP's forecast operating expenditure is that it is only rewarded for efficiency gains above and beyond those already incorporated in the benchmark. This has the effect of not rewarding all efficiency gains, and so raising the risk of a negative carry forward amount despite the fact that the DNSP was efficient and/or understatement of positive carry forward amounts. This result is inconsistent with the requirement of clause 6.5.8(c)(3) for the AER to have regard to the desirability of both rewarding DNSPs for efficiency gains and penalising them for efficiency losses and the revenue and pricing principle in section 7A(3) of the NEL that a DNSP must be provided with effective incentives to promote economic efficiency.

The effect of any efficiency adjustment to the benchmarks will be greatest towards the end of the regulatory control period. For example, an incremental inefficiency in the fourth year of a regulatory control period is carried forward for four years of the next regulatory control period. However, an incremental inefficiency in the first year is only carried forward for a single year of the next regulatory control period.

CitiPower has sought to adjust the operating benchmarks so that the efficiency carryover calculation for the 2006-2010 regulatory period is consistent with the principles set out in the AER's EBSS and with the requirements of clause 6.5.8(c) of the Rules and section 7A(3) of the NEL. As a consequence CitiPower has adjusted its operating expenditure benchmarks to exclude the impact of the partial factor productivity factor in the rate of change factor that was equivalent to -0.39 per cent per annum[56].

The amounts of each of these adjustments and the adjustments in sections 9.6.2 and 9.6.3 above are set out in Attachment C0062. The attachment also sets out CitiPower's proposed calculation of the efficiency carryover amounts.

Table 9-1 sets out CitiPower's calculation of the carryover amounts based on all of the adjustments discussed in this section 9.6.

[56] EDPR 2006-10, page 211 (note that the -0.83 shown for partial factor productivity was an error and the actual number was -0.39 which was corrected in the ESCV's models).

	$'000 (2010)									
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Operating expenditure benchmarks[57]	40,369	41,666	41,834	42,690	43,544					
Operating expenditure benchmarks after adjustments	38,556	39,941	40,184	41,859	42,997					
Outturn operating expenditure - refer section 6	30,196	32,460	30,892	36,168						
Outturn operating expenditure after adjustments	30,196	32,460	30,892	36,168						
Incremental saving	8,360	(879)	1,811	(3,601)	-					
Carryover gains										
2006		8,360	8,360	8,360	8,360	8,360				
2007			(879)	(879)	(879)	(879)	(879)			
2008				1,811	1,811	1,811	1,811	1,811		
2009					(3,601)	(3,601)	(3,601)	(3,601)	(3,601)	
2010						-	-	-	-	-
Carryover amount						5,692	(2,668)	(1,789)	(3,601)	-

Table 9.1: Efficiency benefit sharing scheme 2011-15

9.7 Treatment of negative carryovers from 2006-10

CitiPower proposes that an NPV approach, similar to that applied by the ESCV to the carryover of 2001-2005 efficiency gains and losses in the 2006-10 EDPR, should be applied by the AER to the carryover of 2006-10 efficiency gains and losses. As a result of this NPV approach, carryover amounts for CitiPower under the ESCV's efficiency carryover mechanism for the current regulatory control period should be set at zero.

[57] ESCV, Electricity Distribution Price Review 2006-10 Final decision Volume 1 Statement of Purpose and Reasons, 19 October 2005, p. 196.

Table 9-2 sets out CitiPower's calculation of the carryover amounts for the purposes of paragraphs 10.1 and 10.2 of the RIN after application of the NPV approach to 2006-10 efficiency carryovers.

	$'000 (2010)									
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Operating expenditure benchmarks	40,369	41,666	41,834	42,690	43,544					
Operating expenditure benchmarks after adjustments	38,556	39,941	40,184	41,859	42,997					
Outturn operating expenditure - refer section 6	30,196	32,460	30,892	36,168						
Outturn operating expenditure after adjustments	30,196	32,460	30,892	36,168						
Incremental saving	8,360	(879)	1,811	(3,601)	-					
Carryover gains										
2006		8,360	8,360	8,360	8,360	8,360				
2007			(879)	(879)	(879)	(879)	(879)			
2008				1,811	1,811	1,811	1,811	1,811		
2009					(3,601)	(3,601)	(3,601)	(3,601)	(3,601)	
2010						-	-	-	-	-
Carryover amount						-	-	-	-	-

Table 9.2: Efficiency benefit sharing scheme 2011-15, after application of NPV approach

In the 2001-05 EDPR, the ORG adopted a *'zero floor'* approach for the efficiency carryover, which was described at page 89 as follows:

> *'There will be a floor of zero set on the carryover amount in any one year. That is, there will be no negative carryover in any year. Where the combined carryover from operating and maintenance expenditure plus capital expenditure would be negative, the efficiency carryover will be set to zero for that year, and the implied negative value will be used to offset any positive gain in the following year. Implied negative carryovers will be carried over and accrued in each year, until the end of the regulatory period.'*

The ORG also expressly applied a *'no negative carryover'* approach to the carryover of losses from the 1995-2000 period into the 2001-2005 period (see page 99 of the 2001-05 EDPR).

In the 2006-10 EDPR, the ESCV departed from the ORG's *'zero floor'* approach and instead adopted a *'net present value approach'*. The ESC summarised this NPV approach and the reasons for it on page 424 as follows:

> *'The ORG (2000a, p. 117) stated that efficiency gains and losses would be treated symmetrically in calculating efficiency carryover amounts from the 2001-05 period as this was considered essential to preserving the incentive properties of the mechanism. However, it also accepted that, where negative carryovers were accrued and applied in the 2006-10 period, this might result in distributors receiving less than the building blocks revenue requirement that an efficiently operating distributor would require in that regulatory period.*
>
> *As a result, the ORG foreshadowed that no negative carryover would be applied when incorporating the efficiency carryover amount into the revenue requirement for the 2006-10 regulatory period (referred to as the 'zero floor').*
>
> *The template models accompanying the Commission's framework and approach included application of a net present value (NPV) approach to the zero floor. Under this approach, a negative carryover amount is not applied to the revenue requirement for the 2006-10 regulatory period where the sum of the 2001-05 carryover amounts is negative. Instead, where the sum of accrued efficiency carryover amounts for the 2001-05 regulatory period is negative in NPV terms, the efficiency carryover amount is set to zero for each year of the 2006-10 regulatory period. However, any accrued negative amount could be used to offset positive carryover amounts in the 2011 period. Where the sum of the accrued efficiency carryover amounts for the 2001-05 regulatory period is positive in NPV terms, the efficiency carryover amount is incorporated in the revenue requirement for the 2006-10 regulatory period.*
>
> *The Commission considered that this approach was:*
>
> - *consistent with the objectives of the efficiency carryover mechanism;*
> - *maintained the principle that efficiency gains and losses should both be considered when determining any efficiency reward to be included in the revenue requirement for the next (2006-10) regulatory period; and*
> - *ensured that the building blocks revenue requirement for the next (2006-10) regulatory period would not be less than that required by an efficiently operating distributor.'*

CitiPower proposes that the AER should apply a similar NPV approach to the calculation of carryover amounts from the current regulatory control period for the purposes of the application of the EBSS in the next regulatory control period. Under this NPV approach, a negative carryover amount would not be applied in the EBSS for the next regulatory control period where the sum of the 2006-10 carryover amounts is negative in NPV terms. Instead, where the sum of the carryover amounts for the 2006-10 period is negative in NPV terms, the efficiency carryover amount is set to zero for each year of the 2011-2015 regulatory control period.

CitiPower notes that the ESCV stated in the 2006-10 EDPR at page 435 that:

> *'In so far as the carryover amounts for operating and maintenance expenditure arising from the 2006-10 regulatory period and to be applied in the 2011 regulatory period are concerned, the presumption will be that, where a negative carryover amount arises, it will be applied in calculating the building blocks revenue requirement for the 2011 period. However, taking into account the prevailing regulatory arrangements at that time, future regulators should exercise discretion in determining whether this presumption should be applied to negative efficiency carryover amounts based on the circumstances that have given rise to the negative efficiency carryover amounts.'*

CitiPower considers that the ESCV's justifications for adopting an NPV approach for the current regulatory control period are equally applicable for the next regulatory control period, and that an NPV approach should be applied by the AER for the next regulatory control period.

10. SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

This Chapter details CitiPower's proposed application of the AER's *Electricity Distribution Network Service Provider Service Target Performance Incentive Scheme* (**STPIS**) for Standard Control Services in the next regulatory control period.

Clause 6.4.3(a)(6) of the Rules provides that one of the building blocks is the revenue increments or decrements (if any) for the regulatory year *'arising from the application of a control mechanism in the previous regulatory control period'*. The intention of this provision is to allow the AER to carry over amounts arising under the ESCV's s factor scheme from the 2006-2010 period when making its determination for the next regulatory control period. This increment or decrement is to be carried forward to the next regulatory control period in accordance with clause 6.4.3(b)(6) of the Rules. In May 2009, in accordance with clause 6.6.2 of the Rules, the AER issued the STPIS (a revised version of a scheme issued by the AER in June 2008). The AER's likely approach in its Framework and Approach Paper was that it would apply the reliability of supply and customer service components for the s factor and also the GSL component of the STPIS to CitiPower in the next regulatory control period.

In September 2009, the AER issued proposed revisions to the STPIS (**Proposed STPIS Amendments**). The AER indicated in its *Explanatory statement* to the Proposed STPIS Amendments (at p. 2) that the amendments to the STPIS are likely to be finalised by November 2009 and that the AER will take the amendments into account in making the distribution determination for Victorian distribution businesses. Accordingly, CitiPower includes in this Chapter discussion of the application of the STPIS, as well as the Proposed STPIS Amendments.

10.1 Description of how STPIS will apply

Clause S6.1.3(4) of the Rules requires CitiPower to describe and explain how it considers the STPIS should apply to it in the next regulatory control period.

10.1.1 Current service incentive mechanism

CitiPower has been subject to a similar mechanism to the STPIS in the current regulatory control period, as the ESCV applied a service incentive mechanism under the ESCV's 2006-10 EDPR. This mechanism involves increasing or decreasing CitiPower's weighted average price cap based on changes in its average performance from one year to the next. An s factor is calculated by multiplying the *'performance gap'* for a range of indicators and network types by incentive rates.

CitiPower is also currently subject to a GSL scheme under the Victorian Electricity Distribution Code and the Victorian Public Lighting Code.

10.1.2 Proposed modifications to AER's approach to application of STPIS

Clause 1.3 of the RIN requires CitiPower to provide, in respect of any proposed variations or departures from the application of any component or parameter of the STPIS set out in its AER's Framework and Approach Paper, an explanation of the following:

- the reasons for the variation or departure, including why it is appropriate;
- how the variation or departure aligns with the objectives contained in the STPIS; and
- how the proposed variation or departure will impact the operation of the STPIS.

CitiPower accepts the application of the STPIS, with the exception of the proposed modification of the STPIS proposed by the AER in its Framework and Approach Paper:

- the timing of performance measurement; and
- the definition of the MAIFI parameter.

Each of the proposed modifications are discussed below. In addition, CitiPower's acceptance of the application of the GSL component of the STPIS to it (as contemplated by the AER in the Framework and Approach Paper (at p.103)) is conditional upon the STPIS replacing the existing Victorian GSL scheme applicable under the *Victorian Electricity Distribution Code* and the *Victorian Public Lighting Code* in the next regulatory control period.

Consistent with the STPIS and the AER's proposed approach to its application set out in the Framework and Approach Paper, CitiPower proposes the application of the following components or parameters of the STPIS to it in the next regulatory control period:

- an exclusion threshold based on 2.5 beta unplanned SAIDI;
- the reliability and customer service components of the STPIS, utilising an s factor as defined in the AER's STPIS;
- reliability performance measures of SAIDI and SAIFI for the SCONRRR feeder categories, being urban and CBD feeders;
- a customer service measure based on telephone call answering times;
- a cap on total gains or penalties (*'revenue at risk'*) of 5 per cent of revenue; and
- the electricity distribution network area divided into segments by a CBD feeder and urban feeder network types.

CitiPower is currently subject to a GSL scheme under the *Victorian Electricity Distribution Code* and the *Victorian Public Lighting Code*. Under this scheme, CitiPower is required to make payments to customers who receive service below defined thresholds in relation to: the timeliness of appointments; the timeliness of connections; the frequency and duration of supply; and the timeliness of repairing streetlights.

CitiPower understands that the existing Victorian GSL scheme will be replaced by the GSL component of the AER's STPIS. It is on this basis that CitiPower accepts the application of the GSL component under the STPIS applying to it, on the terms set out in the STPIS, in the next regulatory control period. This is consistent with the AER's likely approach, set out in the Framework and Approach Paper (at p.101), of applying the GSL component of the STPIS to Victorian DNSPs on the basis of its understanding that the existing GSL scheme will not apply in the next regulatory control period.

CitiPower proposes the following modifications to the AER's likely approach to the application of the STPIS set out in the Framework and Approach Paper:

- the use of *'regulatory years'* rather than *'financial years'* for measuring performance for the purposes of setting performance targets for the next regulatory control period and the application of the STPIS in the next regulatory control period;
- the use of data from the regulatory years 2005 to 2009 (inclusive) rather than 2004 to 2008 (inclusive) for measuring performance for the purpose of setting performance targets for the next regulatory control period; and
- the adoption of the ESCV's definition of the MAIFI parameter under the service incentive scheme applicable to Victorian DNSP's in the current regulatory control period, rather than the definition of the parameter as set out in Appendix A of the AER's STPIS.

Regulatory years

The STPIS provides for the calculation of performance targets based on performance over the past five *'financial years'* (clause 3.2.1), and the measurement of performance over *'financial years'* (clause 2.4). However, consistent with the AER's reference to the use of data for *'regulatory years'* in the AER's Framework and Approach Paper and the Proposed STPIS Amendments and for the reasons outlined in the *Explanatory statement* to the Proposed STPIS Amendments, CitiPower proposes to:

- calculate its performance targets based on average performance over the past five *'regulatory years'* (ie calendar years); and
- measure its performance over *'regulatory years'* (calendar years).

CitiPower also proposes to make the consequential modifications outlined in section 5.4.2 of the *Explanatory statement* with respect to the replacement of *'financial years'* and *'years'* with *'regulatory years'*.

CitiPower proposes this modification for the reasons detailed in the Proposed STPIS Amendments (at p.2 of the *Explanatory statement*). The AER stated that the amendment eliminated the scope for gaps in performance measurement to occur, as under the current scheme DNSPs that start their regulatory control period on 1 January must measure their performance on a calendar year basis.

Performance targets determined on the most recent five years

The STPIS and the AER's Framework and Approach Paper (at p.103) contemplate that performance targets for the next regulatory control period should be determined using the most recent actual five years of audited annual performance data. However, whereas the AER contemplates in the Framework and Approach Paper (at p.95) that *'[f]or most Victorian DNSPs … this will be data from the regulatory years 2004 to 2008 (inclusive)'*, CitiPower submits that the audited annual performance data for 2005 to 2009 (inclusive) should be used. That is, CitiPower proposes to calculate its performance targets for 2011 to 2015 based on the average performance over the 2005 to 2009 *'regulatory years'*.

This is proposed because, at the time of both the AER's determination and draft determination, 2005 to 2009 will be the most recent five 'regulatory years' for which audited annual performance data will be available. The impact of the proposed modification on the operation of the scheme will be that the scheme sets performance targets based on the most recent performance data available. It follows that CitiPower proposed modification to the AER's likely approach to the application of the STPIS is consistent with the objectives set out in clause 1.5 of the STPIS.

MAIFI

The AER's proposed definition of MAIFI is stated in Appendix A of the proposed amended STIPIS:

> *'An interruption of 1 minute or less, and continues that in calculating MAIFI, each operation of an automatic reclose device is counted as a separate interruption. Furthermore, sustained interruptions which occur when a recloser locks out after several attempts to reclose should be deleted from MAIFI calculations.'*

The ESCV's definition of MAIFI is based on the Institute of Electrical and Electronics Engineers (**IEEE**) 1366-2003 standard, which defines momentary interruptions as follows:

> *'An interruption of duration limited to the period required to restore service by an interrupting device. Note - Such switching operations must be completed within a specified time of 5 min or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. For example, if a recloser or circuit breaker operates two, three, or four times and then holds*

(within 5 min of the first operation), those momentary interruptions shall be considered one momentary interruption event'.[58]

The ESCV treats one event sequence of re-closes as one interruption for the purposes of measuring MAIFI. This approach is consistent with the IEEE standard 1366. However, the AER's definition of MAIFI could be interpreted as each re-close being an interruption. Such a definition could significantly increase the magnitude of the MAIFI parameter and necessitate adjustment to the historical MAIFI data and the derived targets for 2011-2015.

CitiPower considers applying the AER definition could potentially create the perception that reliability performance of the distribution network has degraded as many incidents where only reported as one interruption will now be regarded as separate interruptions.

CitiPower believes that the ESCV's defined MAIFI is the only data available upon which the AER can reasonably base past performance and derive future momentary reliability targets. Furthermore, adopting the AER's MAIFI definition could characterise those DNSPs that deploy smart network technologies, such as:

- automated feeder reclosing;
- automated HV distribution line reclosing;
- automated supply restoration switching schemes; and
- automated fault detection and system correction

as service providers with an abnormally high momentary reliability index implying the delivery of an inferior supply service.

CitiPower proposes that the application of the STPIS set out in the AER's Framework and Approach Paper be modified by substituting the definition of *'MAIFI'* set out in Appendix A of the STPIS with the ESCV's definition of MAIFI.

CitiPower proposes this modification for consideration by the AER in accordance with clause 2.6 of the STPIS on the basis that it is required to address a transitional issue arising as a result of differences between the MAIFI parameter of the AER's STPIS and the MAIFI parameter of the ESCV's service incentive scheme. (If, contrary to CitiPower's opinion, the AER does not consider clause 2.6 of the STPIS to be applicable to the proposed modification, then CitiPower will propose an amendment to the STPIS in accordance with clause 6.6.2(c) of the Rules and clause 1.8 of the STPIS.)

The STPIS does not explicitly contemplate that a DNSP may propose amendments to the definition of *'MAIFI'* (or any of the other customer service parameters) in its Regulatory Proposal. However, clause 2.6 of the STPIS recognises that transitional issues may arise from one regulatory control period to the next as a result of changes to the scheme's parameters (see clause 2.6(a)). In so doing, the STPIS explicitly states

[58] Attachment 1 to Volume 2 of the ESCV's 2006-10 EDPR

that the AER will give consideration to arrangements to reduce the impact of any such transitional issues and may consider and decide whether the scheme or a component of the scheme should be altered to address a transitional issue (see clause 2.6(b) & (c)). The AER is to consider and decide on whether the scheme or a component of the scheme should be altered to address a transitional issue on the basis of the materiality of the transitional issue, reasonableness and fairness to the DNSP and customers and consistency with the objectives set out in clause 1.5 of the STPIS (see clause 2.6(d)).

CitiPower considers that transitional issue arising from the difference between the STPIS' definition of *'MAIFI'* and the definition of *'MAIFI'* in the ESCV's 2006-10 EDPR is material having regard to the potential consequences outlined above. CitiPower further submits that the proposed modification is the only reasonable outcome for DNSPs and will have no adverse consequences for customers.

Finally, CitiPower considers that its proposed modification is consistent with the AER's objectives for the STPIS set out in clause 1.5 of the STPIS. In particular, the proposed modification is consistent with the AER's obligation under clause 6.6.2(b)(3) of the Rules to take into account the need to ensure benefits to consumers from the scheme warrant any penalty under the scheme for DNSPs and the other incentives for DNSPs under a relevant distribution determination. The penalty that would be imposed on Victorian DNSPs as a result of the change to the MAIFI parameter will not deliver, and thus is not warranted by, any consumer benefit.

10.1.3 Calculation of the s factor

Appendix C of the STPIS provides equations and methodologies outlining the AER's approach to calculating the STPIS adjustments. Appendix E of the STPIS provides a methodology and a worked example outlining the AER's approach for calculating the s factor that is applied to revenues.

CitiPower does not propose any modifications to the methodologies and equations outlined in these Appendices. However, for the purposes of clarity, CitiPower details below its understanding of the approach to calculating the s factor to be applied to revenues contemplated by those Appendices.

- the raw s factor for the telephone answering parameter is calculated using equation (5B) in Appendix C of the STPIS, whereby the difference between the target and actual performance is multiplied by the telephone answering incentive rate and the result is checked to ensure that it does not exceed the upper or lower percentage limits on the revenue at risk (+/- 0.5 per cent);
- the raw s factor for the reliability parameters is calculated by summing the raw s factors for each individual reliability parameter using equation (5A) in Appendix C of the STPIS. For each parameter, the difference between the target and actual performance is multiplied by the incentive rate for the relevant parameter;

- the sum of the raw s factors for all parameters is checked to ensure that it does not exceed the upper or lower percentage limits on the revenue at risk (+/- 2 per cent) using equation (4A) in Appendix C of the STPIS;
- if CitiPower chooses to employ the s-bank mechanism, equation (3) in Appendix C of the STPIS will be applied;
- equation (6) in Appendix C of the STPIS, which is used to account for any step change in the revenue from one regulatory control period to the next, will be applied to the first two years of the next regulatory control period; and
- the effect of the s factor from the previous regulatory year is removed using equation (2) in Appendix C of the STPIS.

The resulting adjusted s factor is applied to the control mechanism using equation (1A) in Appendix C of the STPIS. In this way, the adjusted s factor affects the ARR two regulatory years after the performance giving rise to the s factor is reported.

10.2 Reliability performance parameters

This sub-section deals with CitiPower's proposed treatment of reliability performance parameters under the STPIS.

10.2.1 Reliability measures

In accordance with clause 2.3 of the STPIS and as contemplated by the AER's likely approach to application of the STPIS set out in the Framework and Approach Paper (at p.103), CitiPower proposes that the following reliability measures be applied to the following network types:

- System Average Interruption Duration Index (**SAIDI**) – urban and CBD feeders;
- System Average Interruption Frequency Index (**SAIFI**) – urban and CBD feeders; and
- Momentary Average Interruption Frequency Index (**MAIFI**) – urban and CBD feeders.

10.2.2 Reliability for most recent five years relevant to setting targets

As noted above, CitiPower is proposing to use data from five *'regulatory years'* (ie calendar years) for the purposes of calculating its performance targets in the 2011 to 2015 proposed regulatory control period.

In its Framework and Approach Paper (at p.95), the AER contemplates that *'[f]or most Victorian DNSPs … this will be data from the regulatory years 2004 to 2008 (inclusive)'*.

However, CitiPower proposes to use the audited annual performance data for 2005 to 2009 (inclusive).

This is proposed because, at the time of both the AER's Distribution Determination and Draft Distribution Determination, CitiPower's most recent five years of available audited annual performance data will be for the calendar years 2005 to 2009 (inclusive).

Table 10.1 provides CitiPower's normalised unplanned annual reliability performance for this period, together with the five year average, based on CitiPower's most recent five years of reliability data for the calendar years 2005 to 2009 (estimated values for 2009).

This data excludes planned outages and has been normalised in accordance with Clause 3.3(a) of the STPIS. Table 10.1 will be updated with the final 2009 reliability figures in February 2010. The data presented in the table reflects the exclusion boundary set out in Appendix D to the STPIS adjusted for a 2.5 beta threshold.

Reliability targets	2005	2006	2007	2008	2009♈	Average
CBD						
SAIDI	11.9952	13.9108	6.9427	6.1103	18.8501	11.56182
SAIFI	0.1725	0.2648	0.1444	0.0898	0.2866	0.19162
MAIFI*	0.0076	0.0262	0.0207	0.0003	0.0280	0.01656
Urban						
SAIDI	18.2213	23.5886	23.5463	18.7501	28.4369	22.50864
SAIFI	0.3862	0.4609	0.5214	0.3518	0.5461	0.45328
MAIFI*	0.1728	0.1668	0.1591	0.1616	0.1796	0.16798

Table 10.1 Historic STPIS reliability performance

*MAIFI calculated on the basis of the ESCV definition of MAIFI
♈ Estimated annual value based on first 8 months actuals

CitiPower's indicative reliability targets for the next regulatory control period are based on the average performance over the past five regulatory years, as highlighted in Table 10.1. These targets are based on a calendar year and will be updated once the actual 2009 data becomes available.

10.2.3 Modifications to reliability targets

Clause 3.2.1(a)(1) of the STPIS allows modifications to average reliability performance that reflect:

- any reliability improvements completed or planned, where the planned reliability improvements were proposed in the previous regulatory proposal, the cost of the improvements was allowed by the relevant regulator and the improvements are expected materially to improve supply reliability; and
- any planned reliability improvements, where the planned reliability improvements are included in the expenditure program for the next regulatory control period and are expected materially to improve supply reliability.

The intention of clause 3.2.1(a)(1) of the STPIS was described by the AER as follows (in the *Explanatory Statement and Discussion Paper to the Proposed STPIS* dated April 2008 at p.19):

> *'…the AER has allowed performance targets to be modified to reflect completed or planned reliability improvements where these have been funded directly through a distribution determination and where the reliability improvements are expected to result in a material improvement in reliability. This is to prevent a DNSP from recovering revenue for reliability improvements from both a distribution determination and the operation of the STPIS. … As noted previously, the proposed scheme can also act as a cost-recovery mechanism for service performance improvements where these improvements are not funded through the revenue allowed in a distribution determination'.*

CitiPower does not consider that any modifications are required to the average reliability performance in accordance with clause 3.2.1(a)(1) of the STPIS, because:

- the reliability improvements realised from the previous and current regulatory control period works programs were not funded through the revenue allowed under the applicable distribution determinations; and
- the proposed capital and operating expenditure works program for the next regulatory control period detailed in Chapters 5 and 6 of this Regulatory Proposal does not fund reliability and quality improvements.

Clause 3.2.1(a)(1A) of the STPIS allows CitiPower to propose modifications to average reliability performance to correct for the revenue at risk (the sum of the s factors for all parameters) to the extent it does not lie between the upper limit and the lower limit in accordance with clause 2.5(a) of the STPIS. Clause 3/2.1(a)(1A) is intended *'to allow for the possibility of considering breaches of the revenue at risk cap in setting future performance targets under the scheme'* (see AER's *STPIS Final Decision* of May 2009 at p.17). As the STPIS is not retrospective, clause 3.2.1(a)(1A) does not contemplate the making of adjustments for the first regulatory control period. In any event, CitiPower's historic reliability performance is consistent with the performance targets set by the ESCV and hence no adjustment is necessary. Clause 3.2.1(a)(2) of the STPIS allows CitiPower to propose modifications to average reliability performance that reflect any other factors that are expected to materially affect network reliability performance. CitiPower does not consider that there are any other factors that are expected to materially affect network reliability performance and thus does not consider there are other modifications that need to be made to the normalised unplanned reliability performance averages.

10.2.4 Value of customer reliability (VCR)

For the purposes of clause 3.2.2(d) of the STPIS, CitiPower accepts the AER's VCR value of $47,850 (in September 2008 dollars) for CBD and urban feeders.

In accordance with clause, 3.2.2(b) of the STPIS, the VCR values should be adjusted by CPI to the start of the next regulatory control period, 1 January 2011.

10.2.5 SAIDI and SAIFI weightings

For the purposes of clause 3.2.2(e)-(f) of the STPIS, CitiPower accepts the AER's proposed weightings for SAIDI and SAIFI for the next regulatory control period.

10.2.6 Reliability performance parameter exclusions

For the purposes of clause 3.3 of the STPIS, CitiPower accepts the AER's proposed reliability performance parameter exclusions for the next regulatory control period.

10.2.7 Major event day threshold calculations

Appendix D of the STPIS outlines the methodology by which the Major Event Day threshold is to be calculated. Applying this methodology to the historical data from 2005 to 2009, CitiPower has calculated the Major Event Day threshold for normalising reliability performance for extreme events in the first regulatory control year to be 11.56 minutes for the CBD network type and 22.50 for the Urban network type.

In applying the methodology outlined in Appendix D of the proposed STPIS, CitiPower applied commonly accepted statistical tests for normality to the data set and found that the data whilst not normally distributed could not be adequately approximated by any alternate distribution. Accordingly, CitiPower applied the *'2.5 beta method'*.

The Major Event Day threshold will be updated annually, in accordance with the methodology set out in Appendix D of the STPIS, for each year of the next regulatory control period.

10.2.8 Reliability parameter incentive rates

Clauses 3.2.2(h) and (i) and Appendix B of the STPIS set out how the incentive rates shall be calculated for SAIDI and SAIFI respectively. Clause 3.2.2(k) of the STPIS requires that these incentive rates be calculated at the commencement of the regulatory control period and apply for the duration of the period.

CitiPower will calculate the incentive rates at the commencement of the regulatory control period based on the:

- the VCR expressed in 2010 dollars;
- average annual energy consumption by feeder type; and
- average nominal smoothed ARR.

CitiPower understands that the VCR will be adjusted by CPI to the start of the next regulatory control period, 1 January 2011.

10.3 Customer performance parameters

This sub-section deals with CitiPower's proposed treatment of customer service parameters under the STPIS.

10.3.1 Customer service measures

CitiPower proposes that the only customer service parameter that should be included in the STPIS for the next regulatory control period is the telephone answering parameter. This is consistent with section 4.6.1.5 of AER's Framework and Approach Paper.

10.3.2 Modifications to telephone answering parameter

The AER's definition of the *'telephone answering'* parameter adopted in the STPIS is different to the parameter currently applied under the ESCV's service incentive scheme. However, there is only a marginal difference in recalculating the historical customer service data based on the AER's definition. Assuming the removal of calls abandoned is taken from the numerator and denominator of the calculation.

10.3.3 Customer service parameter revenue at risk

Consistent with clause 5.2(b) of the STPIS, section 4.6.1.5 of the AER's Framework and Approach Paper provides that the AER's likely approach will be to apply a +/-0.5 per cent revenue at risk for each individual customer service parameter for each regulatory year of the regulatory control period.

CitiPower accepts a +/-0.5 per cent revenue at risk is to be applied to the telephone answering parameter for each year of the regulatory control period.

10.3.4 Customer service data for most recent five years used to derive targets

CitiPower proposes to use the audited annual performance data for 2005 to 2009 (inclusive) to derive targets. This is proposed because, at the time of both the AER's determination and draft determination, CitiPower's most recent five years of available audited annual performance data will be for the calendar years 2005 to 2009 (inclusive).

CitiPower's customer service data for the calendar years 2005 to 2009 (2009 being an estimate) based on the *'telephone answering'* parameter definition in Appendix A of the STPIS is provided in Table10.2.

	%					
Target	2005	2006	2007	2008	2009 YTD (Aug)	Average
Percentage of calls answered within 30 seconds	89.15	85.53	87.07	87.70	79.62	86

Table 10.2 Historic telephone answering performance

CitiPower's proposed indicative customer service targets for the STPIS (calculated pursuant to clause 5.3.1(a) of the STPIS), assuming the 'telephone answering' parameter definition in Appendix A of the STPIS applies, are based on the average customer service performance over the last five years, as highlighted in Table 10.2. These targets will be updated once actual 2009 data becomes available.

10.3.5 Telephone answering parameter incentive rate

For the purposes of clause 5.3.2(a) of the STPIS, CitiPower accepts the AER's proposal to apply the incentive rate of -0.04 for the telephone answering parameter for the regulatory control period.

10.3.6 Customer service parameter exclusions

For the purposes of clause 5.4 of the STPIS, CitiPower accepts the exclusions in clause 5.4(a) of the STPIS and does not propose any other exclusions for the telephone answering parameter.

11. DEMAND MANAGEMENT INCENTIVE SCHEME

This Chapter details CitiPower's proposed application of the demand management incentive scheme (**DMIS**) for Standard Control Services in the next regulatory control period.

Clause 6.4.3(a) of the Rules provides that CitiPower's annual revenue requirement for each regulatory year of the next regulatory control period must be calculated using a building block approach. Clause 6.4.3(a)(5) of the Rules provides that one of the building blocks to be used in this approach is to be a revenue increment or decrement (if any) for the regulatory year arising from the application of the DMIS. This increment or decrement is to be calculated in accordance with clause 6.4.3(b)(5) of the Rules.

In May 2009, the AER issued a DMIS for the Victorian DNSPs, in accordance with clause 6.6.3 of the Rules. The details of the DMIS are set out in the AER's guideline entitled *Demand Management Incentive Scheme - Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15* (**Guideline**).

The AER's Guideline provides for the DMIS to contain two potential elements:

Part A – this is a demand management innovation allowance (**DMIA**) that is an annual, ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the regulatory control period; and

Part B – this allows CitiPower to recover revenue forgone in the next regulatory control period resulting from a reduction in the quantity of energy sold directly attributable to a project approved under part A of the DMIS within the regulatory control period.

The AER's likely approach in its Framework and Approach Paper was that it would apply a DMIS to CitiPower in the next regulatory control period that comprises a DMIA, in accordance with Part A, and a mechanism for the recovery of forgone revenue, in accordance with Part B.

Clause S6.1.3(5) of the Rules requires CitiPower to describe and explain how it considers the DMIS should apply to it in the next regulatory control period. CitiPower proposes that:

- Part A of the DMIS, being the DMIA, apply to it in the next regulatory control period;
- the amount of the DMIA should be $200,000 for each year of the next regulatory control period, which is the amount that the AER indicated in its Framework and Approach Paper that it was likely to allow CitiPower;
- the DMIA criteria, expenditure approval process and final year adjustment mechanism all apply in the next regulatory control period, as provided for in section 3 of the AER's Guideline; and

- Part B of the DMIS, being the foregone revenue recovery mechanism, apply in the next regulatory control period.

That is, for the purposes of 1.3 of the RIN, this Regulatory Proposal does not vary or depart from the application of any component or parameter of the DMIS.

CitiPower has not included a revenue increment of $0.2 million (nominal) for the DMIS building block in its calculation of the ARR for each regulatory year of the next regulatory control period in the Post Tax Revenue Model. It would expect the AER to include this as part of its Final Decision.

12. PASS-THROUGH EVENTS

This Chapter details CitiPower's proposed treatment of pass-through events for Direct Control Services in the next regulatory control period.

12.1 Role of pass-through events

CitiPower faces a range of risks in providing its distribution services. Some of these risks are compensated through:

- the Weighted Average Cost of Capital **(WACC)**;
- its operating and maintenance expenditure, such as routine or emergency maintenance; and
- insurance, whether this be self insurance or insurance obtained from a market provider.

However, these three measures will not necessarily cover events whose rarity, unpredictability and/or size are such that:

- it is not possible to insure against these events in the market;
- it would be unreasonable for CitiPower to bear the risks of such events itself, without being able to recover the efficient costs from customers if the events do occur; and
- it would be unreasonable for customers to pay for the costs of such events if the events do not in fact occur.

CitiPower would therefore not have a reasonable opportunity to recover its efficient costs if these are not treated as pass-through events. This would be inconsistent with:

- section 7A of the National Electricity Law (**NEL**), which provides that a regulated network service provider should be able to recover at least its efficient costs; and
- promoting efficient investment in distribution services and thereby the long term interests of customers.

The Australian Energy Market Commission recognised this when drafting the equivalent provisions in Chapter 6A of the Rules, when it said:

> *'The objective of the cost pass-through is to provide a degree of protection from the impact of unexpected changes in costs outside of its control. The Commission considers that such a mechanism provides a reasonable reflection of the operation of a competitive market where efficient costs are eventually passed through to customers, whether they are expected or not. Such a mechanism*

lowers the risks faced by the TNSP, which would otherwise have to be compensated for in the calculation of regulated revenues.'[59]

12.2 Nature of pass-through events

Clause 6.6.1 of the Rules makes provision for a DNSP to pass-through costs associated with certain events. Chapter 10 of the Rules defines the four pass-through events (**defined events**):

- a regulatory change event;
- a service standard event;
- a tax change event; and
- a terrorism event.

The Rules also allow a DNSP to nominate events that it believes should be classified as pass-through events in the next regulatory control period (**nominated events**). Clause S6.1.3(2) of the Rules requires CitiPower to include in its building block proposal a pass though clause with a proposal as to the events that should be defined as pass-through events.

Importantly, CitiPower understands that cost pass-through arrangements in section 6.6.1 of the Rules can apply to both Standard Control Services and Alternative Control Services. This is because, while the cost pass-through provisions are contained in Part C of Chapter 6 of the Rules, which relates to Standard Control Services, clause 6.2.6(c) of the Rules allows the control mechanism for Alternative Control Services to utilise elements of Part C.

Accordingly, unless otherwise stated, the pass-through events discussed in this chapter relate to Direct Control Services, which includes both Standard Control and Alternative Control Services. CitiPower notes that this is consistent with the AER's *Final Decision New South Wales distribution determination 2009-10 to 2013-14* (**NSW Final Decision**), which provided that pass-through provisions for defined and nominated events should be applied to both Standard Control Services and Alternative Control Services.

This chapter identifies the nominated events that CitiPower proposes the AER should approve for the next regulatory control period. These events will have a material effect on CitiPower's costs if they occur and therefore should be included as pass-through events.

CitiPower confirms that its proposed nominated pass-through events:

- relate to Direct Control Services;

[59] AEMC, Australian Energy Market Commission Rule Determination – National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2006, p. 104

- cannot readily be insured either through self insurance or market based insurance; and
- are not otherwise included in CitiPower's expenditure forecasts for the next regulatory control period.

12.3 Nominated pass-through events

In accordance with clauses 6.6.1 and S6.1.3(2) of the Rules, and paragraph 7 of the RIN, this section details certain nominated pass-through events that CitiPower considers should be treated as nominated events.

12.3.1 Regulatory change events

Chapter 10 of the Rules defines a regulatory change event as a change in a regulatory obligation or requirements that:

- falls within no other category of pass-through event;
- occurs during the course of a regulatory control period;
- substantially affects the manner in which the DNSP provides Direct Control Services; and
- materially increases or materially decreases the costs of providing those services.

CitiPower considers that there is uncertainty as to whether the following events fall within the definition of regulatory change event, and accordingly, CitiPower proposed that the following events should be a nominated pass through event in order to provide certainty that they will be treated as a pass through event should they occur in the next regulatory control period:

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework;
- changes in safety regulations introduced by the ESV; and
- changes in exposure limits.

Having regard to the criteria listed by the AER in the NSW Final Determination as the factors that it will have regard to when determining whether an event should be nominated as a pass through event[60], CitiPower confirms that in relation to each of these events:

- the event is not captured by the defined events (unless the AER confirms in the distribution determination that it will treat the event as a regulatory change event if it occurs during the next regulatory control period);

[60] AER, Final Decision on the NSW Distribution Determination 2009-10 to 2013-14, 28 April 2009, p. 277

- the event is clearly defined;
- for reasons set out below in relation to each event, despite being foreseeable the timing and cost impact of the event can not be reasonably forecast by CitiPower at the time of preparing this Regulatory Proposal;
- the associated costs will not otherwise be recovered through any other mechanism, and in particular the event is not already insured against and can not be self insured;
- the occurrence of this event is beyond CitiPower's control and CitiPower is not the party that is in the best position to manage the risk of the event occurring and therefore bear the risk; and
- the passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

12.3.1.1 Transfer of non-pricing distribution regulatory arrangements to a national regulatory framework

This event refers to changes to CitiPower's jurisdictional non-pricing distribution regulatory functions and obligations as a result of national reforms that are currently being progressed by the Federal, State and Territory Governments. The transfer of the jurisdictional regulatory and legislative instruments that govern non-price distribution activities to the national level is a key energy market reform under the Australian Energy Market Agreement (**AEMA**). As currently proposed, this includes:

- creating the National Energy Customer Framework;
- creating a national customer connections framework;
- potentially sunsetting the Victorian Electricity Distribution Code; and
- potentially sunsetting various ESCV Guidelines that are currently in force[61].

Any changes to the existing arrangements could have significant cost impacts that have not been reflected into the forecast expenditure for the 2011-15 regulatory control period in this Regulatory Proposal.

CitiPower believes that it is appropriate to treat the transfer of non-pricing distribution regulatory arrangements to a national regulatory framework as a nominated pass-through event because:

- the future treatment of jurisdictional instruments and the nature of any future national frameworks is not known at the time of preparing this Regulatory Proposal;

[61] For example, ESCV's Electricity Industry Guideline 14 — Provision of Services by Electricity Distributors, April 2004

- the transfer of existing jurisdictional functions and obligations to a national framework may materially increase the cost of providing Direct Control Services and therefore CitiPower's ability to achieve its expenditure objectives in the next regulatory control period;
- the associated costs are not included in any other category of pass-through event and will not otherwise be recovered through any other mechanism; and
- the occurrence of this event is beyond CitiPower's control.

12.3.1.2 Changes to electrical safety regulations

This event refers to changes to CitiPower's electrical safety obligations as a result of changes to the Victorian *Electricity Safety Act 1998* (**Act**) and associated Regulations and any outcomes arising from the Victorian Bushfire Royal Commission that have not otherwise been included in forecast expenditure.

As discussed in section 6.5 of this Regulatory Proposal and Regulatory Template 4.1, the Act and associated Regulations set the electrical safety obligations that CitiPower must meet. The requirements of the Act and the Regulations are enforced by ESV. CitiPower notes that:

- the Act is currently being amended, however these amendments have not yet been finalised; and
- a number of regulations made under the Act will sunset over the next regulatory control period.

Accordingly, changes to the existing electrical safety obligations may impact on CitiPower's construction and maintenance obligations and therefore could have significant cost impacts that are not included in the forecast expenditure for the 2011-15 regulatory control period in this Regulatory Proposal.

CitiPower therefore believes that it is appropriate to treat changes to its electrical safety obligations as a nominated pass-through event because:

- the extent of these changes is not known at the time of preparing this Regulatory Proposal;
- these changes may materially increase the cost of providing Direct Control Services and therefore CitiPower's ability to achieve its expenditure objectives in the next regulatory control period;
- the associated costs are not included in any other category of pass-through event and will not otherwise be recovered through any other mechanism; and
- the occurrence of this event is beyond CitiPower's control.

12.3.1.3 Changes to exposure limits

This event refers to changes to exposure limits introduced in the final version of the current Draft Radiation Protection Standard for Exposure Limits to Electric and Magnetic Fields 0Hz-3kHz, by the Australian Radiation Protection and Nuclear Safety Agency (**ARPANSA**).

This Standard, when finalised, will replace the NHMRC publication, Radiation Health Series No 30, Interim Guidelines on limits of exposure to 50/60Hz electric and magnetic fields (1989).

CitiPower therefore believes that it is appropriate to treat changes to exposure limits as a nominated pass-through event because:

- these changes are not known at the time of preparing this Regulatory Proposal;
- these changes may materially increase the cost of providing Direct Control Services and therefore CitiPower's ability to achieve its expenditure objectives in the next regulatory control period;
- the associated costs are not included in any other category of pass-through event and will not otherwise be recovered through any other mechanism; and
- the occurrence of this event is beyond CitiPower's control.

12.3.2 Other nominated events

CitiPower proposes that the following events be treated as nominated pass through events in the next regulatory control period:

- a general nominated pass through event;
- a financial failure of a retailer event;
- a declared retailer of last resort event;
- an AEMO fees or charges event; and
- an emissions trading scheme event.

Having regard to the criteria listed by the AER in the NSW Final Determination as the factors that it will have regard to when determining whether an event should be nominated as a pass through event, CitiPower confirms that in relation to each of these events:

- the event is not captured by the defined events;
- the event is clearly identified in the definitions set out below for each event;

- for the reasons set out below in relation to each event, despite being foreseeable, the timing and cost impact of the event cannot be reasonably forecast by CitiPower at the time of preparing this Regulatory Proposal;
- the associated costs will not otherwise be recovered through any other mechanism, and in particular the event is not already insured against and cannot be self-insured;
- the occurrence of this event is beyond CitiPower's control and CitiPower is not the party that is in the best position to manage the risk of the event occurring and therefore bear the risk; and
- the passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

12.3.2.1 General nominated pass through event

In the NSW Final Determination, the AER included a 'general nominated pass through event' for Country Energy, Energy Australia and Integral Energy. The AER defined this pass through event as follows:[62]

> ***A general nominated pass through event*** *occurs in the following circumstances:*
>
> *1. An uncontrollable and unforeseeable event that falls outside of the normal operations of the business, such that prudent operational risk management could not have prevented or mitigated the effect of the event, occurs during the next regulatory control period*
>
> *2. The change in costs of providing distribution services as a result of the event is material, and is likely to significantly affect the DNSP's ability to achieve the operating expenditure objectives and/or the capital expenditure objectives (as defined in the transitional chapter 6 rules) during the next regulatory control period*
>
> *3. The event does not fall within any of the following definitions:*
>
> *'regulatory change event' in the NER (read as if paragraph (a) of the definition were not a part of the definition);*
>
> *'service standard event' in the NER;*
>
> *'tax change event' in the NER;*
>
> *'terrorism event' in the NER;*
>
> *'retail project event' in this final decision;*

[62] AER, Final Decision on the New South Wales Distribution Determination 2009-2010 to 2013-2014, 28 April 2009, pages 295-296.

'smart meter event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition);

'emissions trading scheme event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition);

'aviation hazards event' in this final decision.

For the purposes of this definition:

- an event will be considered unforeseeable if, at the time the AER makes its distribution determination, despite the occurrence of the event being a possibility, there was no reason to consider that the event was more likely to occur than not to occur during the next regulatory control period

- 'material' means the costs associated with the event would exceed 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

This general nominated pass through event replaced the force majeure event that had been proposed by the NSW DNSPs as a nominated pass through event and which the AER had indicated in its NSW Draft Determination that it would accept as a nominated pass through event.

In the Australian Competition Tribunal's decision on Energy Australia's application for review of the NSW Final Determination (*Application by Energy Australia and Others* [2009] ACompT 8), the Tribunal accepted the common submission from Energy Australia and the AER that the definition of the general nominated pass through event in the NSW Final Determination contained three errors. CitiPower has not seen the exact variations to the definition that were proposed by Energy Australia and the AER, but based on the contents of the Tribunal's decision it appears to CitiPower that the proposed amendments are appropriate and should be made to the definition set out above.

CitiPower proposes a general nominated pass through event as a nominated pass through event for the reasons set out by the AER in the NSW Final Determination. The definition of a general nominated pass through event would be as set out above (subject to the amendments referred to in the Tribunal's decision), except for amendments to the definitions in paragraph 3 to reflect the list of other nominated pass through events that are accepted by the AER and the applicable materiality threshold.

CitiPower believes that it is appropriate that it be able to pass through the costs arising from a general nominated pass through event in the next regulatory control period that relate to Direct Control Services. This is because:

- the financial impacts arising from a general nominated pass through event are not known at the time of preparing this Regulatory Proposal;

- a general nominated pass through event may materially increase the cost of providing Direct Control Services and therefore CitiPower's ability to achieve its expenditure objectives in the next regulatory control period;
- the associated costs are not included in any other category of pass through event and will not otherwise be recovered through any other mechanism; and
- the occurrence of this kind of event is beyond CitiPower's control.

12.3.2.2 Financial failure of a retailer

A retailer failure event occurs if a retailer is placed in administration or liquidation, or their licence is revoked, such that CitiPower is not paid revenues from the provision of distribution services to which it would otherwise be entitled. A financial failure of a retailer pass-through event should cover the difference between the amount CitiPower would have been entitled to had the retailer not failed, less any amount that is recovered pursuant to those protections within its use of system agreement.

CitiPower emphasises that, while it takes steps to protect itself against the failure of a retailer, the current regulatory arrangements (ie credit support arrangements) constrain the extent to which it can effectively do this. In particular, the current credit support arrangements provide that a retailer is only required to pay credit support to a DNSP when the amount of the retailer's average billed and unbilled network charges exceeds its credit allowance. In practice, this means that CitiPower holds almost no credit support on the basis of the retailer's credit ratings. Furthermore, it is likely that CitiPower would not receive credit support from a retailer that demonstrates financial stress, such as through late payment of network charges.

Accordingly, CitiPower believes that the current credit support arrangements are not effective as they do not require upfront payment by all retailers to ensure that CitiPower is financially protected against the risk of non-payment by a retailer. CitiPower considers that the pass-through for the financial failure of a retailer is essential and appropriate because the:

- financial impacts arising from a retailer failure are not known at the time of preparing this Regulatory Proposal;
- the failure of a retailer may materially increase the cost of providing Direct Control Services and therefore CitiPower's ability to achieve its expenditure objectives in the next regulatory control period;
- the associated costs are not included in any other category of pass-through event and will not otherwise be recovered through any other mechanism; and
- the occurrence of this kind of event is beyond CitiPower's control.

CitiPower emphasises that the ESCV recognised the potential for this kind of event and provided a pass-through for the financial failure of a retailer[63] in its 2006-10 EDPR.

[63] ESCV, 2006-10 EDPR Vol 1, page 488

CitiPower proposes that a financial failure of a retailer event would be defined in the same way as in the 2006-10 EDPR,[64] subject to modifications to reflect the current terminology under the Rules. CitiPower's proposed definition is:

> **A financial failure of a retailer event** means the occurrence of an event whereby a retailer is placed in administration or liquidation, and as a consequence a DNSP does not receive revenue which it was otherwise entitled to for the provision of direct control services.

12.3.2.3 Declared retailer of last resort event

If a retailer of last resort (**ROLR**) event is triggered, specified procedures take effect under Division 8 of Part 2 of the *Electricity Industry Act 2000* including processes to provide for the transfer of customers of the failed retailer to the retailer of last resort. In such an event, DNSPs may incur significant additional administrative costs in transferring customers from the failed retailer to the retailer of last resort in a short period of time. These costs include manually updating internal databases and the Market Settlement and Transfer Solution (**MSATS**). MSATS is the NEM solution managed by the AEMO for: the transfer of customers between retailers; management of standing data; administration of National Metering Identifier (**NMI**) registration; and facilitation of NMI Discovery.

Accordingly, CitiPower considers that the pass-through for a declared ROLR event is appropriate because the:

- financial impacts arising from a ROLR event are not known at the time of preparing this Regulatory Proposal;
- a ROLR event may materially increase the cost of providing Direct Control Services and therefore CitiPower's ability to achieve its expenditure objectives in the next regulatory control period;
- the associated costs are not included in any other category of pass-through event and will not otherwise be recovered through any other mechanism; and
- the occurrence of this kind of event is beyond CitiPower's control.

CitiPower emphasises that the ESCV recognised the potential for this kind of event and provided a pass-through for a 'declared' ROLR event in the 2006-10 EDPR, where these costs are material and cannot be recovered through another mechanism[65].

CitiPower proposes that a declared retailer of last resort event would be defined in a similar manner as in the 2006-10 EDPR,[66] subject to modifications to reflect the current terminology under the Rules. CitiPower's proposed definition is:

[64] ESCV, 2006-10 EDPR Vol 2, page 71
[65] ESCV, 2006-10 EDPR Vol 1, page 488
[66] ESCV, 2006-10 EDPR Vol 2, page 70

> **A declared retailer of last resort event** means the occurrence of an event whereby an existing retailer is unable to continue to supply electricity to its customers and those customers are transferred to the declared retailer of last resort, and which:
>
> (a) falls within no other category of pass through event; and
>
> (b) materially increases the costs of providing direct control services.

12.3.2.4 Australia Energy Market Operator (AEMO) fees or charges event

AEMO, which formally commenced operations on 1 July 2009, has the power under section 52 of the NEL to impose on a distributor fees and charges for the services AEMO provides under the NEL or Rules to the energy market more generally. Section 52 of the NEL also provides that AEMO may have the right to impose fees and charges under jurisdictional legislation.

If AEMO imposes fees or charges, then CitiPower considers that it should be able to pass-through these costs because the:

- financial impacts arising from such a fee are not known at the time of preparing this Regulatory Proposal;
- such a fee may materially increase the cost of providing Direct Control Services and therefore CitiPower's ability to achieve its expenditure objectives in the next regulatory control period;
- the associated costs are not included in any other category of pass through event and will not otherwise be recovered through any other mechanism; and
- the occurrence of this kind of event is beyond CitiPower's control.

CitiPower proposes that an AEMO fees or charges event would be defined as follows:

> **An AEMO fees or charges event** means the imposition by AEMO of a fee or charge under the NEL or any relevant jurisdictional legislation, other than a charge for a service that is provided on request to a specific DNSP and which is not payable by other DNSPs, and which:
>
> (a) falls within no other category of pass through event; and
>
> (b) materially increases the costs of providing direct control services.

12.3.2.5 Emissions trading scheme event

In the NSW Final Determination, the AER accepted an 'emissions trading scheme event' as a nominated pass through. The AER defined this pass through event as follows:[67]

[67] AER, Final Decision on the New South Wales Distribution Determination 2009-2010 to 2013-2014, 28 April 2009, pages 286-287.

> ***An emissions trading scheme event*** *is an event which results in the imposition of legal obligations on a DNSP arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth or NSW Government during the course of the next regulatory control period and which:*
>
> *(a) falls within no other category of pass through event; and*
>
> *(b) materially increases the costs of providing direct control services.*

CitiPower proposes an emissions trading scheme event as a nominated pass through event for the reasons set out by the AER in the NSW Final Determination. The definition of an emissions trading event would be as set out above, except for amending the reference to the *'NSW Government'* to *'Victorian Government'*.

12.4 Materiality threshold for assessing pass-through events

Clause 6.6.1(j) of the Rules sets out the relevant factors that the AER must take into account in determining a positive or negative pass-through amount.

The Rules do not require that a materiality threshold should be specified for events nominated in a distribution determination, albeit that clause 6.2.8(a)(4) of the Rules provides that the AER may publish a guideline in relation to its likely approach to determining materiality in the context of possible pass-through events. CitiPower notes that:

- the AER has yet to publish a national guideline on materiality thresholds in the context of pass-through events;
- Chapter 10 of the Rules provides that (in this context) the word *'materiality'* has its ordinary meaning;
- in its Distribution Determinations for the NSW and ACT DNSPs, the AER raised the possibility of a *'bright-line'* materiality threshold of:
    - a revenue impact in any one year which exceeds 1 per cent of the DNSP's revenue for the first year of the regulatory control period; or
    - proposed capital expenditure which exceeds 5 to 7 per cent of the aggregate annual revenue requirement in the first year of the regulatory control period.[68]

Paragraph 7.1(a)(ii) of the RIN requires CitiPower to propose a materiality threshold for each nominated pass-through event and paragraph 7.1(b) of the RIN further requires that CitiPower explain:

- whether the proposed materiality threshold applies to both positive and negative pass-through events); and

[68] AER, *'Issues Paper: Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-2014'* November 2007 at section 4.4.1.

- why the proposed materiality threshold is appropriate.

The RIN defines *'materiality threshold'* as *'The minimum dollar value in terms of capital and operating expenditure for a pass-through event'*. CitiPower interprets this to mean that the AER will:

- assess pass-through events on the basis of their cost to, rather than their revenue impact on, CitiPower; and
- add operating and capital expenditure amounts together for the purposes of assessing whether they meet the materiality threshold.

CitiPower supports this interpretation.

In response to the RIN requirements, CitiPower proposes that:

- the materiality threshold for each nominated pass-through event, for the purposes of paragraph 7.1(a)(ii) of the RIN, should be $5 million over the regulatory control period. For clarity, CitiPower considers that:
  - its costs should be assessed over the five year regulatory control period, rather than in any single year of the regulatory control period; and
  - the same materiality threshold should apply to all pass-through events;
- the $5 million materiality threshold should apply, for the purposes of paragraph 7.1(b)(i) of the RIN, to both positive and negative pass-through events; and
- a $5 million materiality threshold is appropriate because:
  - it is sufficiently large that it will have a significant impact on CitiPower's financial position over the regulatory control period; but
  - it is not so small as to have the potential to trigger large numbers of pass-through applications over the course of the regulatory control period, which would impose an unreasonable administrative burden on both CitiPower and the AER.

CitiPower notes that the AER has defined *'material project'* in the RIN to be $5 million (or $2 million where the project relates to the capital expenditure categories Non Network Assets – IT, Non Network Assets – Other or SCADA and Network Control).

12.5 Pass-through mechanism

The control mechanism in the AER's Framework and Approach paper does not contain an explicit provision for the recovery of costs associated with any approved cost pass-through events.

Chapter 18 of this Regulatory Proposal proposes a basis for the AER enabling CitiPower to recover the costs associated with any approved cost pass event through the control mechanism.

13. DEPRECIATION

This chapter details CitiPower's forecast depreciation building block for Standard Control Services for the next regulatory control period.

13.1 Depreciation requirements

Clause 6.4.3(a) of the Rules provides that CitiPower's annual revenue requirement for each year of the next regulatory control period must be calculated using a building block approach. Clause 6.4.3(a)(3) of the Rules provides that one of the building blocks to be used in this approach is to be depreciation. Clause 6.4.3(b)(3) of the Rules requires this forecast to be determined in accordance with clause 6.5.5 of the Rules, which details the basis on which depreciation must be calculated and CitiPower's depreciation schedules must be presented.

Clause S6.1.3(12) of the Rules also requires CitiPower's Building Block Proposal to provide certain information in relation to its depreciation building block for the next regulatory control period. This information is provided in this Chapter of the Regulatory Proposal and the accompanying Roll Forward Model and Post Tax Revenue Model.

13.2 Calculation of depreciation

Chapter 6 of the Rules provides general guidance in relation to the calculation of the depreciation building block for Standard Control Services. Whilst the Rules do not mandate a specific depreciation methodology, the AER's Post Tax Revenue Model applies a straight line depreciation methodology. This is consistent with the methodology that CitiPower has applied in the current regulatory control period.

CitiPower proposes to continue to apply a straight line depreciation methodology in the 2011–15 regulatory control period in relation both to:

- the opening Regulatory Asset Base (**RAB**) for the next regulatory control period; and
- the forecast capital expenditure to be added to the Regulatory Asset Base in the next regulatory control period.

CitiPower has used the AER's Post Tax Revenue Model to calculate the depreciation building blocks, in accordance with clause 6.5.5 of the Rules. The Post Tax Revenue Model assumes that capital expenditure is incurred in the middle of the year and the corresponding assets are assumed to be commissioned at the end of the year. Therefore, new assets start to be depreciated from the start of the year following the year in which the capital expenditure arises. New assets are depreciated according to standard lives for each asset class. Existing assets are depreciated over their remaining asset lives.

As a consequence of applying the AER's Post Tax Revenue Model, and in accordance with the requirements of clause 6.5.5(b) of the Rules, CitiPower's depreciation schedules:

- use a profile that reflects the nature of the assets over their economic lives;
- result in the sum of the real value of any asset over its economic life (calculated as at the time the value of the assets was first included in the Regulatory Asset Base) being equivalent to the value at which that asset or category of assets was first included in the Regulatory Asset Base; and
- are calculated using depreciation methods and rates that are consistent with those determined for the same assets on a prospective basis in the distribution determination for that regulatory control period.

CitiPower confirms that, in accordance with clause S6.1.3(12) of the Rules the AER's Post Tax Revenue Model:

- includes depreciation schedules that apply well accepted categories, such as asset classes or category drivers;
- includes details of all amounts, values and other inputs that it has used to compile the depreciation schedules; and
- demonstrates that the depreciation schedules conform with the requirements set out in clause 6.5.5(b) of the Rules.

13.3 Asset categories

CitiPower has calculated depreciation using the same asset categories as those applied for the current regulatory control period.

13.4 Standard and remaining asset lives

The economic life of an asset is the estimated period that the asset will be able to be used to perform its current, or intended, function. Clause 6.5.5(b)(1) requires that depreciation must be based on the economic life of the assets or category of assets. This permits CitiPower to have its capital returned to it at a rate which is consistent with the decline in the economic value of the assets.

CitiPower has applied the same standard asset lives for the 2011–15 regulatory control period as applied by the ESCV in the current regulatory control period. There have been no factors identified that would suggest that the expected life of assets utilised by CitiPower has materially changed.

The remaining lives of existing assets at 1 January 2011 have been determined consistent with the proposed standard asset lives. Table 13.1below provides the standard and remaining asset lives for each asset class.

	Standard	Remaining
Subtransmission	50.0	22.7
Distribution system assets	51.0	22.9
Metering	15.0	6.1
Public lighting	25.0	14.1
SCADA/Network control	13.0	7.6
Non-network - IT	6.0	5.2
Non-network - Other	15.0	8.5

Table 13.1: Asset lives (years)

13.5 Depreciation building blocks

CitiPower has prepared its depreciation building blocks for the 2011-15 regulatory control period for Standard Control Services by applying:

- the 1 January 2011 opening asset balances determined in Chapter 14 of this Regulatory Proposal;
- the roll forward methodology applied in Chapter 14 of this Regulatory Proposal;
- the forecast inflation rate in Chapter 15 of this Regulatory Proposal;
- the capital expenditure forecast in Chapter 5 of this Regulatory Proposal;
- the asset disposals forecast in Chapter 14 of this Regulatory Proposal; and
- applying the asset lives listed in Table 13.1.

The AER's Post Tax Revenue Model has been used to calculate CitiPower's depreciation schedule that is shown in Table 13.2 below.

	2011	2012	2013	2014	2015
Subtransmission	6.9	7.7	8.5	9.4	10.3
Distribution system assets	47.7	52.1	57.1	62.4	67.7
Metering	5.6	5.8	5.9	6.1	6.2
Public lighting	0.7	0.8	0.8	0.8	0.8
SCADA/Network control	1.9	2.3	2.8	3.2	3.7
Non-network – IT	0.6	2.3	4.0	5.9	8.7
Non-network – Other	1.3	1.5	1.9	2.2	2.5
Equity raising costs	-	0.1	0.2	0.3	0.4
Total	64.70	72.50	81.20	90.30	100.30

Table 13.2: Depreciation schedule ($m, nominal)

14. REGULATORY ASSET BASE (RAB)

This chapter details the calculation of CitiPower's RAB for its Standard Control Services for the current and next regulatory control periods.

14.1 RAB requirements

Clause 6.4.3(a)(1) of the Rules provides that the indexation of the RAB is to be one of the building blocks to be used in calculating the Annual Revenue Requirement for the next regulatory control period. Clause 6.4.3(b)(1) of the Rules requires that this indexation be undertaken in accordance with:

- clause 6.5.1 of the Rules, which details the basis on which the AER must develop and publish a model to roll forward the RAB between regulatory years;
- clause S6.2 of the Rules, which provides information on establishing the opening RAB for the next regulatory control period and rolling the RAB forward between years. Clause S6.2.1(c)(1) of the Rules specifies that the value of CitiPower's RAB must be determined by rolling forward the 1 January 2006 value of $1,625.5 million (in July 2004 dollars); and
- clause S6.2.3(c)(4) of the Rules, which details the basis for applying inflation to the RAB between regulatory years.

In addition:

- clause S6.1.3(7) of the Rules requires CitiPower's Building Block Proposal to include certain information in relation to the calculation of the RAB for each regulatory year, using its Roll Forward Model; and
- clause S6.1.3(10) of the Rules requires CitiPower to provide a completed Post Tax Revenue Model and Roll Forward Model.

This information is provided in this Chapter of the Regulatory Proposal and the accompanying completed Post Tax Revenue Model and Roll Forward Model.

14.2 Establishing the 1 January 2006 opening RAB value

CitiPower has prepared a Roll Forward Model in order to determine the opening RAB for Standard Control Services as at 1 January 2011.

14.2.1 Specified value as at 1 January 2006

CitiPower's 1 January 2006 opening RAB of $1,626.5 million (in July 2004 dollars) in clause S6.2.1(c)(1) of the Rules is built up from the asset values in Table 14.1. These values have been sourced from a copy of the ESCV's model that was used for the 2006-10 EDPR for CitiPower.

Asset category	RAB value
Subtransmission	122.7
Distribution system assets	739.6
Metering	43.6
Public lighting	31.4
SCADA/Network control	16.0
Non-network - IT	25.6
Non-network - other	12.0
Total	990.9

Table 14.1: Opening RAB as at 1 January 2006 ($m, real 2004)

14.2.2 Adjustment to the 1 January 2006 RAB

Clause S6.2.1(c)(2) of the Rules requires the RAB value of $1,625.5 million (in July 2004 dollars) in clause S6.2.1(c)(1) of the Rules to be adjusted for the difference between:

- any estimated capital expenditure for any part of a previous regulatory control period; and
- the actual capital expenditure for that part of the previous regulatory control period.

Table 14.2:

- shows the revised value of the RAB having regard for the requirements of clause S6.2.1(c)(2) of the Rules; and
- escalates the RAB value to a nominal value.

Clause 6.5.1(e)(3) of the Rules requires that the escalation must be consistent with the method used for the indexation of the control mechanism for Standard Control Services during the preceding regulatory control period. The ESCV's 2006-10 EDPR required the indexation of the control mechanism to be based on the nine month lagged annual increase in inflation, where inflation is based on the CPI All Groups, Weighted Average of Eight Capital Cities published by the Australian Bureau of Statistics.

Asset category	RAB value
Subtransmission	129.5
Distribution system assets	780.3
Metering	46.0
Public lighting	33.1
SCADA/Network control	16.9
Non-network - IT	27.1
Non-network - other	12.7
Total	1,045.6

Table 14.2: Opening RAB as at 1 January 2006 adjusted for the difference between estimated and actual capital expenditure ($m, nominal)

14.2.3 Roll forward of the RAB to 1 January 2011

CitiPower has prepared a Roll Forward Model in order to roll forward the RAB for Standard Control Services to 1 January 2011. This has involved:

- adding the actual prudent capital expenditure, net of actual customer contributions, for the 2006 to 2008 calendar years to the RAB, as detailed in Chapter 5 of this Regulatory Proposal. This is inclusive of expenditure related to the CBD Security of Supply project;
- adding the estimated capital expenditure, net of estimated customer contributions, for the 2009 and 2010 calendar years to the RAB, as detailed in Chapter 5 of this Regulatory Proposal. This is inclusive of expenditure related to the CBD Security of Supply project;
- deducting the actual disposals for the 2006 to 2008 calendar years from the RAB;
- deducting the estimated disposals for the 2009 and 2010 calendar years from the RAB;
- deducting the regulatory depreciation from the ESCV's 2006-10 EDPR for the 2006 to 2010 calendar years from the RAB inclusive of regulatory depreciation associated with the CBD Security of Supply project;
- indexing the RAB for each calendar year of the 2006 to 2010 regulatory control period by applying the actual All Groups CPI Weighted Average of Eight State Capital Cities published by the Australian Bureau of Statistics for the years 30 September 2005 to 30 September 2009 respectively.

At the time of preparing this Regulatory Proposal, the values of actual capital expenditure (net of actual customer contributions) and actual disposals for the 2009 and 2010 calendar years were not available. By 30 April 2010, CitiPower will be able to provide the AER with its audited net capital expenditure and disposals for 2009 and its Roll Forward Model updated to reflect 2009 actual net capital expenditure and disposals.

The actual 2010 values will not be available for the AER's Final Distribution Determination so the roll forward will continue to apply the estimated capital expenditure (net of estimated customer contributions) and estimated disposals for the 2010 calendar year.

For the purposes of establishing the opening RAB at the start of the next regulatory control period in accordance with clause 6.12.1(18) of the Rules, CitiPower has used regulatory depreciation as opposed to actual depreciation.

Table 14.3 shows the roll forward of CitiPower's RAB for the five years of the current regulatory control period. The closing RAB as at 31 December 2010 forms the opening RAB for the next regulatory control period.

	2006	2007	2008	2009	2010
Opening RAB	1,014.8	1,060.9	1,105.8	1,134.9	1,223.0
Net capital expenditure	83.6	73.6	79.6	101.2	124.7
Disposals	0.4	0.6	0.1	-	-
Depreciation	67.8	69.9	71.2	69.6	72.0
Indexation of RAB	30.7	41.8	20.6	56.5	15.4
Closing RAB	1,060.9	1,105.8	1,134.9	1,223.0	1,291.0

Table 14.3: Roll forward of the RAB from 1 January 2006 to 31 December 2010 ($m, nominal)

The completed Roll Forward Model provides a detailed breakdown of the roll forward of CitiPower's RAB to 1 January 2011.

14.3 Roll forward of RAB from 1 January 2011

CitiPower has rolled forward the RAB for Standard Control Services for the next regulatory control period from 1 January 2011 using the Post Tax Revenue Model. This has involved:

- adding the forecast capital expenditure (net of Customer Contributions) as detailed in Chapter 5 of this Regulatory Proposal;
- deducting the forecast depreciation;
- deducting forecast asset disposals as shown in Table 14.4; and
- indexing the annual closing RAB using the forecast inflation rate for each year of the regulatory control period.

The projected RAB at the end of each calendar year of the next regulatory control period is detailed in Table 14.4.

	2011	2012	2013	2014	2015
Opening RAB	1,291.0	1,471.3	1,672.7	1,881.4	2,089.4
Net capital expenditure	213.5	238.0	249.0	252.1	253.1
Disposals	-	-	-	-	-
Depreciation	64.8	72.6	81.1	90.2	100.3
Indexation of RAB	31.6	36.0	40.9	46.0	51.1
Closing RAB	1,471.3	1,672.7	1,881.4	2,089.4	2,293.2

Table 14.4: Roll forward of the RAB from 1 January 2011 to 31 December 2015 ($m, nominal)

The completed Post Tax Revenue Model provides a detailed breakdown of roll forward of CitiPower's RAB to 31 December 2015.

For the purposes of establishing the opening RAB at the start of the 2016-20 regulatory control period in accordance with clause 6.12.1(18) of the Rules, CitiPower will use actual depreciation.

15. RATE OF RETURN ON CAPITAL

This chapter details the calculation of CitiPower's proposed rate of return on capital for its Standard Control Services for the next regulatory control period.

15.1 Return on capital requirements

Clause 6.4.3(a)(2) of the Rules provides that a return on capital is one of the building blocks to be used in calculating the Annual Revenue Requirement for Standard Control Services. Clause 6.4.3(b)(2) of the Rules provides that this forecast is to be determined in accordance with clause 6.5.2 of the Rules.

Clause 6.5.2(a) of the Rules provides that the return on capital for a regulatory year is to be calculated by applying a rate of return to the RAB.

Clause 6.5.2(b) of the Rules provides that the return on capital must be calculated as a nominal post-tax weighted average cost of capital, in accordance with a prescribed formula.

Clause 6.5.4 of the Rules details the basis on which the AER must develop a Statement of Regulatory Intent (**SoRI**) in relation to the rate of return.

Clause 6.12.1(5) of the Rules provides that a decision on whether to apply or depart from a value, method or credit rating level set out in a SoRI is one of the constituent decisions of the AER's Distribution Determination.

On 1 May 2009, the AER issued its SoRI in accordance with clauses 6.5.4 and 6.16 of the Rules. Under the SoRI, the current default values for the WACC parameters are as follow:

- r_f is to be calculated on a moving average basis from the annualised yield on Commonwealth Government Securities (**CGS**) with a maturity of ten years. The period is to be as close and reasonably practicable to the commencement of the regulatory control period;
- ße is 0.80;
- MRP is 6.5 per cent;
- the value of debt as a proportion of the value of equity and debt (**D/V**) is 0.60;
- the credit level rating is BBB+; and
- the assumed utilisation of imputation credits (γ) is 0.65.

Clause S6.1.3(9) of the Rules requires the Building Block Proposal to propose CitiPower's calculation of the rate of return, including to detail any proposed departure from the values, methods or credit rating levels set out in the applicable SoRI.

15.2 Proposed departures from the SoRI

Paragraph 8.1 of the RIN requires CitiPower to identify each proposed departure from a WACC parameter as specified in the SoRI. As disclosed by the discussion below, CitiPower does not propose any departures from the SoRI, except in respect of the market risk premium (**MRP**) and the value of the assumed utilisation of imputation credits (γ). Whereas the SoRI contemplated a value of gamma of 0.65 and a value for the MRP of 6.5 per cent, CitiPower submits that a gamma value of 0.5 and a MRP value of 8.00 per cent should be adopted.

Paragraph 8.2 requires CitiPower to provide, for each proposed departure from the SoRI, all supporting consultants' reports and documents, including those specified in paragraph 8.2 of the RIN. CitiPower addresses paragraph 8.2 of the RIN in respect of its proposed departure from the value of gamma and the value of the MRP contemplated by the SoRI below in section 15.9 of this Regulatory Proposal.

15.3 Averaging period in days and commencement date for bond rates

Clause 6.5.2(c)(2) of the Rules allows CitiPower to propose the period of time over which the moving average of the annualised yield on Commonwealth Government bonds with a maturity of ten years is to be calculated.

Clause S6.1.3(8) of the Rules requires CitiPower's Building Block Proposal to propose the commencement and length of the period for the purposes of calculating the nominal risk free rate under clause 6.5.2(c)(2) of the Rules.

Attachment C0078 of this Regulatory Proposal contains CitiPower's proposed averaging period in days, and commencement date, for the measurement of the nominal risk free rate. CitiPower requests that, in accordance with clause 6.5.2(c)(2)(iii) of the Rules, this Attachment C0078 be kept confidential.

For the purpose of this regulatory proposal, a 15 business day averaging period commencing on 1 October 2009 and ending on 21 October 2009 has been adopted to enable the calculation of the proposed rate of return at the time of lodging this proposal.

15.4 Nominal risk free rate

Clause 6.5.2(c)(2) of the Rules specifies that the nominal risk free rate is (unless some different provision is made by a relevant SoRI) the rate determined for that regulatory control period on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of ten years using the indicative mid rates published by the Reserve Bank of Australia.

For the purposes of this Regulatory Proposal, CitiPower has calculated the nominal risk free rate over the first 15 business days of October 2009 in accordance with the proxy described in clause 6.5.2(c)(2) of the Rules. CitiPower has estimated the appropriate rate by interpolating on a straight line basis between the March 2019 and the April 2020 Commonwealth Government bond yields.

15.5 Value of debt as a proportion of the value of equity and debt

In accordance with the SoRI, CitiPower proposes to adopt a 0.6 value of debt as a proportion of the value of equity plus debt.

15.6 Debt risk premium

The return required on debt is estimated by summing the risk free rate and the debt risk premium, which is the additional return required to investors for assuming the corporate risk attached to a particular firm.

Clause 6.5.2(e) of the Rules provides that the debt risk premium represents the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds, which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit agency.

The SoRI provides that the credit level rating to apply when calculating the debt risk premium is BBB+.

The Bloomberg fair value curve has generally be accepted by Australian economic regulators as an appropriate method to derive a benchmark allowance for the cost of debt for a regulated business. CitiPower is proposing to derive its debt risk premium from the Bloomberg fair value curve over the averaging period.

CitiPower recognises that during times of financial market crises the Bloomberg fair value curve may not be sufficiently reliable to use. As such, CitiPower is proposing the use of a methodology developed by PricewaterhouseCoopers (**PwC**) to review the robustness of the Bloomberg fair value curve over the averaging period.

The Victorian electricity distributors commissioned PwC to provide expert advice on the following questions in relation to the determination of debt risk premium:

- propose a methodology to test whether the Bloomberg fair value curves that the AER has relied on in previous determinations reasonably meets the legislative requirements;
- propose an alternative methodology for calculating the debt risk premium that best meets the legislative requirements should Bloomberg fail the above test; and
- apply the Bloomberg test and, if necessary, the alternative methodology during the first 15 business days in October 2009.

Attachment C0079 of this Regulatory Proposal contains the PwC expert report. PwC propose three tests for Bloomberg based on:

- coefficient of variation in bank feeds;

- average differential between Bloomberg generic yield and mean of bank feed yields; and
- mean yield differential between the Bloomberg fair value curve and the Bloomberg generic yield of each bond.

Should the Bloomberg fair value curve fail these tests, PwC propose a hierarchy of actions to be undertaken to determine a debt risk premium which reasonably meets the legislative requirements.

PwC applied their proposed Bloomberg test over the first 15 business days in October and concluded that the Bloomberg fair value curve reasonably meets the legislative requirements. PwC calculate the Bloomberg BBB seven-year debt risk premium to be 4.18 per cent over the first 15 business days in October. PwC propose a linear extrapolation to ten years, resulting in a debt risk premium is 4.71 per cent.

CitiPower proposes that the methods set out by PwC be applied during the averaging period proposed in Attachment C0078. These methods include:

- the Bloomberg fair value curve tests;
- the method of extrapolation of the Bloomberg fair value curve, if the PwC method requires it to be used; and
- the recommended approach when the Bloomberg fair value curve test finds the Bloomberg fair value curve to be flawed.

For the purpose of this Regulatory Proposal CitiPower has applied the debt risk premium of 4.71 per cent as calculated by PwC over the first 15 business days in October.

15.7 Equity beta

In accordance with the SoRI, CitiPower proposes to adopt an equity beta value of 0.8.

15.8 Market risk premium

The MRP is the expected return over the risk-free rate that investors would require in order to invest in a well-diversified portfolio of risky assets. The MRP represents the risk premium that investors who invest in such a portfolio can expect to earn for bearing only non-diversifiable risk.

In the Review of the WACC Parameters **(WACC Final Decision)** the AER concluded that a MRP of 6.5 per cent was reasonable, at the time of the SoRI Decision, and is an appropriate estimate of the forward looking long term MRP commensurate with the conditions in the market for funds that are likely to prevail from a 10 year perspective.

Persuasive evidence to justify a departure from the SoRI

Clause 6.5.2(g) of the Rules states that:

> *'A distribution determination to which a statement of regulatory intent is applicable must be consistent with the statement unless there is persuasive evidence justifying a departure, in the particular case, from a value, method or credit rating level set in the statement.'*

Clause 6.5.2(h)(2) of the Rules provides that in deciding whether a departure from a value, method or credit rating level set in a statement of regulatory intent is justified in a distribution determination, the AER must consider:

> *'whether, in the light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes a value, method or credit rating level set in the statement inappropriate.'*

CitiPower considers that there is persuasive evidence available now that demonstrates that a value of 6.5 per cent for the MRP is inappropriate and that in the particular case of the forthcoming determination for CitiPower, departure from the 6.5 per cent MRP value specified in the SoRI is justified. The evidence suggests that the current cost of raising equity is now well above that implied by the SoRI. This evidence comes in the form of:

- the implications of the ongoing market volatility for the current cost of equity; and
- the spreads on bond yields relative to the MRP based on the SoRI.

CitiPower's reasoning and evidence is set out below. It also shows that while estimating the ex ante MRP is extremely difficult, this is not a reason to provide an MRP which does not reflect the current cost of equity. Indeed, given the level of uncertainty in the market, and the need for investment, it reinforces the need to err of the side of ensuring that allowed revenues are at least sufficient to allow for efficient investment.

15.8.1 The basis for the AER's decision on the MRP in the SoRI

In its WACC Final Decision, the AER noted that its obligation under the Rules to set a rate of return that was forward-looking and which reflects prevailing market conditions should be interpreted in the following way:

> *'… it is a requirement that the AER must have regard to the need for the rate of return to reflect forward looking expectations, as at the relevant point in time. That relevant point in time is at the time of the individual reset determinations, rather than at the time of the WACC Final Decision.'*[69]

The AER further noted that for parameters such as the MRP, a difficulty arises since the Rules require the AER to lock-in either a value or methodology, but in the case of the MRP – which does vary over time according to economic conditions – there is no adequate method of automatically updating the MRP at the time of each reset determination. A clear risk with locking-in a value for the MRP at each WACC

69 WACC Final Decision, p188

review, particularly when market conditions are highly uncertain, is that this value may change materially at the time of a reset determination, such that it no longer supports a forward-looking rate of return at that time. There is therefore a degree of tension between the requirement to lock-in a value for the MRP at the WACC review and the requirement to have regard to the need for the rate of return to reflect forward-looking expectations commensurate with prevailing conditions at the time of each reset determination.

The AER acknowledged this situation as follows:

> *'…if the MRP varies over time, then by definition, the locking in of a value may not always completely reflect forward looking expectations prevailing at the time of each reset determination. Accordingly, for some reset determinations the actual (unobservable) MRP may be somewhat above this value, though for other reset determinations the actual (unobservable) MRP maybe be somewhat below.'*[70]

CitiPower's next regulatory control period is to commence on 1 January 2011. Whilst there has been emerging evidence of a recovery in economic conditions in the Australian market in recent months, it would be premature to suggest with any confidence that a turnaround has occurred and that the market cost of equity has returned to levels that preceded the global financial crisis. Indeed, there is a strongly held view that any further recovery over the near term may reverse, or at best, is likely to be mild. As the Organisation for Economic Co-operation and Development has noted in its recent Interim Economic Assessment, despite positive signs of a turnaround on many indicators:

> *'… numerous headwinds imply that the pace of the recovery is likely to be modest for some time to come. Ample spare capacity, low levels of profitability, high and rising unemployment, anaemic growth in labour income and ongoing housing market corrections will moderate any uptick in private demand. At the same time, the need remains for households, businesses, financial institutions and governments to repair the damage to their balance sheets.'* [71]

Similar observations have also recently been made by the Reserve Bank of Australia (**RBA**). In a recent speech by Malcolm Edey, RBA Assistant Governor, it was noted that despite encouraging signs of improvement in recent months, it is necessary to exercise cautious optimism:

> *'… Given these developments, my theme today is one of cautious optimism about the global situation. We can't yet say that things are back to normal, and we still can't rule out further setbacks …*
>
> *… the extreme risk aversion of late last year has been easing for some months now, and the banks' access to wholesale funding markets has been improving. It's important to keep this in perspective: these market indicators are still, in*

70 WACC Final Decision, p191

71 OECD, What is the Economic Outlook for OECD countries? An Interim Assessment, 3 September 2009, page 2.

some cases, a long way from pre-crisis levels, particularly for borrowing costs at longer maturities.'[72]

The prevailing market outlook therefore supports the view that any sustained improvement in market conditions is still highly uncertain and a return to pre-crisis conditions is some considerable way off. In particular, page 3 of the RBA's latest (August 2009) Statement on Monetary Policy notes that significant uncertainty remains regarding the economic outlook, with the possibility that the recovery since the March 2009 quarter may be short-lived:

'Given the rapidly evolving international financial and economic conditions, the outlook for the Australian economy continues to be subject to considerable uncertainty, although the risks are more balanced than they have been for some time. With confidence globally still fragile, it remains possible that the outlook could again weaken.'

Given this outlook, CitiPower believes that at the time the AER makes its forthcoming determination, it is likely that the return on equity required by investors in the market will reflect a level of risk aversion which exceeds that reflected in the value allowed for the MRP in the SoRI[73.]

15.8.2 Market volatility and the current cost of equity

New evidence has become available which indicates that the best estimate for the MRP over the 2011-2015 regulatory control period is 8.0 per cent per annum.

CitiPower considers that the unique environment within which the AER is undertaking its review of this Regulatory Proposal justifies a departure, in this particular case, from the MRP value specified in the SORI. In particular, the ongoing uncertainty regarding the global capital market outlook and the impact of this uncertainty on investors' required returns, coupled with the new evidence presented below, constitute relevant factors (pursuant to clause 6.5.4(h)(2) of the Rules) that justify a departure from the SoRI's MRP value. CitiPower's view is supported by the following conclusions of Bishop and Officer, which are set out in Attachment C0194:

- their estimate of the current forward looking MRP is 12.0 per cent per annum;
- their best estimate of the MRP over the regulatory period (i.e. January 2011 - December 2015) is in the range of 7 – 10.6 per cent per annum; and
- they recommend adopting an MRP of 8.0 per cent for the regulatory period.

15.8.3 The spreads on bond yields relative to the AER's view of the MRP

Based on prevailing yields on 10 year Commonwealth Government Securities (5.5 per cent), the implied required return on equity, inclusive of the value of imputation credits, using the values in the SoRI for the MRP and equity beta is approximately 10.7

[72] Edey, M. "The evolving financial situation", speech delivered at the Finsia Financial Services Conference, 28 October 2009.

[73] This implicitly requires holding the equity beta constant at the value allowed in the SoRI.

per cent. By contrast, the required return on 10 year BBB+ debt, as estimated by Bloomberg, is around 10.2 per cent. That is, using the current SoRI values, it would appear that shareholders are willing to invest for a rate of return that is only 50 basis points higher than the rate at which financiers are willing to provide fixed rate BBB+ rated 10 year debt.

This result seems anomalous, particularly given the substantially higher levels of risk that equity holders bear relative to debt providers. There is simply no logical basis on which to conclude that equity investors would be prepared to invest for such a small margin over the return which debt holders can get. Furthermore, the relative historical risk premiums between debt and equity investment in the Australian market do not support this result.

The returns available on debt compared to the implied returns available on equity using the estimate of the MRP outlined in the SoRI demonstrate that the latter is the inadequate.

CitiPower considers that the information and analysis set out above (and in the report of Bishop and Officer) provides persuasive evidence available that demonstrates that a value of 6.5 per cent for the MRP is inappropriate, and that in the particular case of the forthcoming determination for CitiPower, departure from the 6.5 per cent MRP value specified in the SoRI is justified. CitiPower's proposed MRP is set out below

15.8.4 CitiPower's proposed MRP

The AER is obliged to provide CitiPower with a rate of return which is set to appropriately reflect market conditions at the time of its determination. The new evidence provided in this Regulatory Proposal indicates that the SoRI value for the MRP significantly understates the MRP that is likely to prevail over the 2011-2015 regulatory control period. Therefore, if it were to be applied, to set CitiPower's cost of capital over the forthcoming regulatory control period, there would be insufficient incentives for efficient investment in electricity distribution infrastructure over the period, and this would be contrary to the long term interests of consumers and hence the National Electricity Objective.

CitiPower considers that there is a strong case for the AER to depart from the SoRI value for the MRP for this particular determination, given:

- the on-going uncertainty regarding the outlook for global economic and capital market conditions;
- the new evidence presented regarding investors' forward-looking required rates of return in the present environment of on-going high uncertainty; and
- CitiPower's contention that under these circumstances, applying the MRP value specified in the SoRI would deliver an outcome that is inconsistent with the National Electricity Objective and the Revenue and Pricing Principles set out in the National Electricity Law.

CitiPower considers that the matters noted above are relevant factors (pursuant to clause 6.5.4(h)(2) of the Rules) that justify, in this particular case a departure from the MRP value specified in the SoRI.

Based on the evidence presented in this Regulatory Proposal and Attachment C0194, CitiPower considers that there is persuasive evidence to adopt a value for the MRP of 8 per cent for the purpose of the AER's determination for the forthcoming regulatory control period.

15.9 Utilisation of imputation credits

15.9.1 AER Review of WACC parameters

The SoRI determined a value for the utilisation of imputation credits **(gamma)** of 0.65. This particular value was adopted by the AER following the conclusion of its review of the WACC parameters in May 2009.

The WACC Final Decision adopted an approach to valuing imputation credits in accordance with the Monkhouse definition. Under this approach, *'gamma'* (γ) is defined as the product of:

- the imputation credit payout ratio (F); and
- the utilisation rate or the market value of imputation credits actually distributed (theta).

A value for F of 1.0 is adopted by the AER in its WACC Final Decision.

In the WACC Final Decision the AER determined that in relation to the value of theta:

- the lower bound estimate is 0.57, based on the AER's best estimate of theta inferred from market prices; and
- the upper bound estimate is 0.74 is based on the AER's best estimate of theta from tax statistics.

The WACC Final Decision considered that it is reasonable to apply equal weight to the lower and upper bound theta estimates, and to round to the nearest 0.05. This generates a point estimate of theta of 0.65, which combined with the assumed imputation credit payout ratio of 1.0, produces a value for gamma of 0.65. On this basis, the WACC Final Decision concluded that a reasonable estimate of gamma is 0.65.

15.9.2 Proposed value of gamma

The AER adoption of a payout ratio of 1.0 in its WACC Final Decision is extreme because:

- not all imputation credits are paid out; and

- not all imputation credits are paid out in the year that the credit is created, and therefore there is a time value loss for investors.

Whilst quantification of the payout ratio may be difficult, it must be less than 1.0 for the above mentioned reasons[74].

In setting the lower bound for theta, the AER relied on the *'2006 Beggs and Skeels study'*[75]. In adopting the 2006 Beggs and Skeels study, the WACC Final Decision expressed some concerns with, and ultimately rejected a study by Strategic Finance Group[76] **(the SFG study)** which had been submitted by the Joint Industry Associations during the AER's WACC review.

Following the publication of the WACC Final Decision, the Victorian and South Australian electricity distributors commissioned Associate Professor Skeels (through solicitors Gilbert and Tobin) to provide an independent review of matters relating to the estimation of the value of theta. In accordance with paragraph 8.2 of the RIN, the Skeels' independent review is contained in Attachment C0082 of this Regulatory Proposal. The data relied on by Skeels, the assumptions and calculations used by Skeels to transform this data, the modelling code used and results of Skeels' analysis (including the results of any statistical tests conducted to demonstrate the robustness of the data and the code used to conduct those tests) is contained in Attachments C0113, C0114, C0115 and C0116.

In undertaking his review Skeels has produced persuasive evidence which demonstrates that there has been a material change in circumstances in relation to the estimation of the value for gamma since the publication of the SoRI. The material change in circumstances is the fact that the AER based its SoRI decision in relation to the lower bound for theta on the 2006 Beggs and Skeels study, but one of the co-authors of that study now considers that the estimate of theta set out in that study is not accurate having regard to the most recent data. In light of that change in circumstances, it would be inappropriate for the AER to continue to rely on the 2006 Beggs and Skeels study and to continue to adopt a lower bound for theta of 0.57.

Skeels has reviewed the SFG study and the associated comments contained in the AER's WACC Final Decision. During the course of his independent review, Skeels sought further information from SFG regarding issues raised by the AER in relation to the SFG report. Skeels concludes that the most accurate estimate of theta is 0.23:

> *'I find that the results presented in Appendix I constitute an empirically valid study of the dividend drop-off problem for Australia and that the SFG estimate of theta of 0.23 represents the most accurate estimate currently available.*
>
> *It is clear that the more recent data used in the SFG results presented in Appendix I favour an estimate of theta that is lower than that of 0.57 which was obtained by*

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[74] ETSA 2010-15 Regulatory Proposal attached statements from Professor Officer and Mr Feros of Gilbert and Tobin which provide evidence that the payout ratio is less than 1.0

[75] Market Arbitrage of Cash Dividends and Franking Credits, published in The Economic Record in 2006 (Volume 82 (258), 239-252)

[76] SFG Consulting, *The value of imputation credits as implied by the methodology of Beggs and Skeels (2006)*, Report prepared for ENA, APIA and Grid Australia, 1 February 2009.

Beggs and Skeels on the basis of less recent data. However, it might be argued that the minor methodological differences that remain between the methodology of Beggs and Skeels (2006) and that of SFG bias their estimate of theta downwards. (This is not a position to which I subscribe and I present it only in the garb of a devil's advocate.) Were such a position to be taken then, in my opinion, a compelling case can be made that the empirical evidence overwhelmingly supports the notion that the true value of theta lies between the SFG estimate of 0.23 and the Beggs and Skeels (2006) estimate of 0.57, and that in all probability it lies closer to 0.23 than 0.57.'[77]

The AER expressed some concerns with, and placed limited weight on the SFG study. In relation to that study, page 447 of the AER's WACC Final Decision states:

'Despite the advantage of providing more up-to-date estimates (ie to 2006), the AER has concerns regarding the reliability of the SFG study, and considers that correction of identified deficiencies would likely have a material impact on the results. Accordingly while the AER has given full consideration to the SFG study, limited weight has been placed upon theta estimates generated by the SFG study for the purposes of this final decision'.

The independent report of Associate Professor Skeels confirms that the SFG study adopts an analytical approach (namely, the use of a regression-based methodology focusing on the post 1 July 2000 period) which is consistent with that favoured by the AER in its WACC Final Decision. Associate Professor Skeels' report also notes that once SFG's analysis had been reworked to address the concerns expressed by the AER in the WACC Final Decision, the SFG analysis provides an estimate of theta of 0.23, which represents the most accurate estimate currently available. Importantly, Associate Professor Skeels' independent report states his expert opinion that the more recent data used in the SFG analysis favour an estimate of theta that is materially lower than that of 0.57 which was obtained by Beggs and Skeels, and which was relied on by the AER in its WACC Final Decision.

The evidence presented in Skeels' independent report is new evidence that was not taken into account by the AER when making its SoRI decision. The circumstances relating to the AER's estimate of the value of gamma have changed to the extent that data that was previously relied on by the AER in making its SoRI decision has now been acknowledged by one of the co-authors to be inconsistent with the most recent data, and data that was previously rejected by the AER has now been shown to be the best available data on which an estimate of theta should be based.

CitiPower contends that this evidence means that, in light of the underlying criteria adopted in the WACC Final Decision, a lower bound estimate of theta of 0.57 is inappropriate, and instead the correct lower bound estimate of theta is 0.23.

Accordingly, taking the correct lower bound theta value of 0.23, and the upper bound theta value (0.74) set out in the WACC Final Decision, and applying the methodology

[77] Christopher L Skees, A Review of the SFG Dividend Drop-Off Study, A report prepared for Gilbert and Tobin, 28 August 2009, p5.

adopted by the WACC Final Decision to select a point estimate of theta from the reasonable range, the correct theta value is 0.5.

Based on the evidence presented above and in the relevant accompanying appendices, CitiPower proposes that the AER should depart from the gamma value of 0.65 set out in the SoRI and for the forthcoming regulatory control period a value of 0.5 should be adopted for gamma.

15.10 Expected inflation rate

The expected inflation rate is not used to calculate the nominal vanilla WACC, although it underpins some of the WACC parameters and is therefore determined in conjunction with the WACC parameters.

The proposed method for determining the expected inflation rate is to take a geometric average of the forecast inflation rate for each year over the ten year period starting from the commencement of the 2011-15 regulatory control period, where the annual expected inflation rates are taken from:

- the most recent annual forecast of inflation by the Reserve Bank of Australia (**RBA**); and
- for the remaining years in the ten year period, the mid point of the RBA target inflation range, that is 2.50 per cent per annum.

This approach is based on the approach taken by the AER in the NSW Final Determination.

At the time of preparing this proposal, the most recent RBA inflation forecast was 2.00 per cent for 2011. Adopting the mid point of the RBA inflation target for the remaining nine years results in a geometric average expected inflation rate of 2.44 per cent. CitiPower has applied this inflation rate in this Regulatory Proposal.

15.11 Proposed WACC parameters

CitiPower proposes WACC parameters and methods that, at the time of preparing this Regulatory Proposal, deliver a nominal vanilla WACC of approximately 10.86 per cent. In reaching this value, CitiPower has adopted values for the WACC parameters as shown in Table 15.1.

With the exception of the market risk premium and the value of utilisation of imputation credits, the parameter values and methods used in Table 15.1 are consistent with those specified in the Rules and SoRI.

Parameter	Value
Nominal risk free rate (Rf)	5.47%
Inflation rate (f)	2.44%
Equity beta (ße)	0.8
Market risk premium (MRP)	8.00%

Value of debt as a proportion of the value of equity and debt (D/V)	60%
Debt risk premium (DRP)	4.71%
Utilisation of imputation credits (γ)	0.5
Nominal WACC	10.86%

Table 15.1: WACC parameter values

Prior to the Final Decision, the nominal risk free rate and debt risk premium will be replaced with data from the agreed averaging period and expected inflation rate will be updated with the most recent RBA inflation forecasts.

15.12 Equity raising costs

Equity raising costs relate to costs associated with raising equity to enable CitiPower's proposed capital expenditure program to be undertaken. Equity raising costs are not reported in CitiPower's operating or capital expenditure in its Regulatory Accounts and therefore a separate benchmark forecast has been included in the building block for the next regulatory control period.

In the AER's Final Decision New South Wales distribution determination 2009-10 to 2013-14 (**NSW Final Decision**), it was confirmed in relation to equity raising costs, that:

- external equity funding, as distinct from debt or internal funding, may be the necessary choice for capital raising at particular points in the life of a business;
- new equity raising may lead a business to incur costs such as legal fees, brokerage fees, marketing and other transaction costs;
- these are upfront expenses with minimal or no ongoing costs over the life of the equity; and
- equity raising costs are a legitimate cost for a benchmark efficient business where external equity funding is the least-cost option available.

Equity raising costs have *'notionally'* been treated as capital expenditure forecast reflecting the nature of equity is such that it exists over the life of the assets being funded.

CitiPower has derived an estimate of direct equity raising costs of 4 per cent based on analysis undertaken for ETSA Utilities by the Competition Economists Group **(CEG)**. This contrasts with the benchmark allowance of 2.75 per cent determined by the AER in the New South Wales Final Decision. CEG's report is provided as Attachment C0059 to this Regulatory Proposal.

ETSA Utilities' advice from CEG, obtained subsequent to the New South Wales Final Decision, indicates that there is a strong basis for a DNSP to also include the indirect costs of equity raising in its capital expenditure forecasts. On the basis of CEG's advice, CitiPower has conservatively estimated its indirect equity raising costs at 3 per cent. As set out in detail in CEG's report, the 3 per cent figure represents the average of the lowest published estimates.

CitiPower has therefore adopted an equity raising cost calculation which includes the recognised indirect costs of equity raising, based on the lowest published estimates found and documented in CEG's expert report.

The benchmark dividend reinvestment plan cost of 1 per cent and the benchmark 30 per cent dividend reinvestment, as determined by the AER in its New South Wales Final Decision, has also been adopted by CitiPower. Consistent with the WACC Final Decision on the value of imputation credits, a 100 per cent payout of imputation credits is assumed.

The required equity has been determined in accordance with values extracted from the Post Tax Revenue Model. The direct, indirect and dividend reinvestment plan costs described above, have been used to determine the benchmark equity raising costs.

In addition to the above equity raising costs, CitiPower faces additional costs in equity raising, which in the current economic climate are significant. The current state of the global economy has led to additional requirements being imposed by credit rating agencies to ensure that impending equity funding is being appropriately addressed by businesses. These requirements are being more strictly monitored and the cost of satisfying the requirements has risen significantly. When CitiPower raises equity, in order to maintain its credit rating, it must implement one of a number of options well in advance of the equity requirement to ensure that it is not exposed to movements in capital markets at the time the equity is required and to provide assurance that the equity can be secured. Attachment C0069 is an article from Standard and Poors on refinancing and attachment C0058 is a letter response from Standard and Poors clarifying their position. These attachments indicate that to avoid negative rating consequences a corporate would need to issue equity no less than three months ahead of the equity requirement.

This being the case, CitiPower has included within its forecast early equity raising costs. CitiPower has assumed that a DNSP will issue equity (via a dividend reinvestment plan or new equity raising) three months prior to maturity, at the benchmark cost of equity, and invest the early issued equity in Treasury notes over those three months. CitiPower has applied the benchmark cost of equity and Treasury note interest rate as measured over the first 15 business days in October 2009, and proposes that the Treasury note interest rate be recalculated over the measurement period proposed in Attachment C0078.

The total equity raising costs indicated in Table 15.2 below comprise the sum of direct and indirect equity raising costs and early equity funding costs, which have both been calculated as set out in Attachment C0081 to this Regulatory Proposal.

	$'000 (real 2010)					
	2011	2012	2013	2014	2015	Total
Equity raising costs	3,992	4,067	4,008	3,723	2,737	18,527

Table 15.2: Equity raising costs 2011-15

16. ESTIMATED COST OF CORPORATE INCOME TAX

This chapter details the calculation of CitiPower's estimated cost of corporate income tax for its Standard Control Services for the next regulatory control period.

16.1 Corporate income tax requirements

Clause 6.4.3(a)(4) of the Rules provides that the estimated cost of corporate income tax is a building block to be used in calculating the Annual Revenue Requirement for Standard Control Services. Clause 6.4.3(b)(4) of the Rules provides that this forecast is to be determined in accordance with clause 6.5.3 of the Rules.

Clause 6.5.3 of the Rules details the formula for calculating the estimated cost of corporate income tax (**ETCt**).

However, clause 11.17.2(b) of the Rules, which applies to the calculation of CitiPower's estimated cost of corporate income tax for the next regulatory control period, requires that the AER must adopt:

- the taxation values of assets carried over from the ESCV's 2006-10 EDPR;
- the classification of assets, and the method of classification, adopted for the ESCV's 2006-10 EDPR; and
- the same method of depreciation as was adopted for the ESCV's 2006-10 EDPR.

Clause 11.17.2(c) of the Rules provides that the AER may depart from the methods of asset classification or depreciation provided for under clause 11.17.2(b) of the Rules to the extent required by changes in the taxation laws or rulings given by the Australian Taxation Office.

The taxation values of assets, classification of assets, method of classification and method of depreciation underpinning the EDPR are set out in the ESCV's financial model for CitiPower (ESCV financial model).

16.2 Opening taxation values of assets

The ESCV financial model rolls forward the taxation values of assets from 1 January 2000 to 31 December 2010. The roll forward begins in the last year of the previous regulatory control period because capital expenditure is estimated for the last year of a regulatory control period. In keeping with this methodology, the Roll Forward Model prepared by CitiPower commences the roll forward of the taxation values of assets from 1 January 2005. CitiPower's taxation values of assets carried over from the EDPR as at 1 January 2005 are shown in Table 16.1.

	Value
Pre-Ralph	
Land	34.5
6.7 to 10 yrs	-
10 to 13 years	4.5
13 to 30 years	4.0
> 30 years	207.9
Post-Ralph	
Demand related capital expenditure	197.4
Replacement expenditure (Group 1)	-
Replacement expenditure (Group 2)	6.6
Replacement expenditure (Group 3)	6.5
Environment, safety and legal	0.9
Standard metering (Group 1)	1.3
Standard metering (Group 2)	-
SCADA/Network control	7.8
Non-network general assets - IT	17.3
Non-network general assets - Other	7.9
Total	496.7

Table 16.1: Opening taxation values of assets as at 1 January 2005 ($m, nominal)

16.3 Tax depreciation rates and method

Table 16.2 sets out the tax depreciation rates applied in the 2006-10 EDPR.

	Depreciation rate
Pre-Ralph	
Land	0%
6.7 to 10 yrs	30%
10 to 13 years	25%
13 to 30 years	20%
> 30 years	10%
Post-Ralph	
Demand related capital expenditure	3.00%
Replacement expenditure (Group 1)	100.00%
Replacement expenditure (Group 2)	7.50%
Replacement expenditure (Group 3)	3.00%

Environment, safety and legal	7.50%
Standard metering (Group 1)	37.50%
Standard metering (Group 2)	10.00%
SCADA/Network control	7.50%
Non-network general assets - IT	40.00%
Non-network general assets - Other	17.65%

Table 16.2: Tax depreciation rates

In calculating tax depreciation, the Roll Forward Model applies:

- the same classification of assets as applied for the 2006-10 EDPR, shown in Table 16.1 and Table 16.2;
- the same tax depreciation rates as applied for the 2006-10 EDPR, shown in Table 16.2; and
- the same tax depreciation method as applied for the 2006-10 EDPR, that is, the diminishing value method.

16.4 Roll forward of the tax value of assets

In rolling forward the tax values of assets, the PTRM uses:

- opening taxation values of assets carried over from the 2006-10 EDPR, shown in Table 16.1;
- tax depreciation calculated as described in section 16.3; and
- actual gross capital expenditure for 2005-08 and forecast gross capital expenditure for 2009-15.

At the time of preparing this Regulatory Proposal, actual gross capital expenditure for the 2009 and 2010 calendar years is not available. By 30 April 2010, CitiPower will be able to provide the AER with its audited gross capital expenditure for 2009 and its updated tax depreciation calculation to reflect 2009 actual gross capital expenditure. The actual 2010 values will not be available for the AER's Final Distribution Determination. Therefore, the roll forward of the taxation values of assets will continue to apply the estimated values for 2010. The difference between the estimated and actual values will be reflected in the roll forward of taxation values of assets for 2016-20.

Table 16.3 shows the roll forward of the taxation value of assets to the end of the current regulatory control period.

	2005	2006	2007	2008	2009	2010
Opening tax asset value	496.7	523.1	559.5	595.0	645.5	718.6
Capital expenditure	84.3	90.9	87.1	108.9	127.9	140.5
Depreciation	57.9	54.5	51.6	58.4	54.8	62.2
Closing tax asset value	523.1	559.5	595.0	645.5	718.6	797.0

Table 16.3: Roll forward of taxation value of assets from 1 January 2005 to 31 December 2010 ($m, nominal)

Table 16.4 shows the roll forward of the taxation value of assets through the 2011-15 regulatory control period.

	2011	2012	2013	2014	2015
Opening tax asset value	797.0	962.9	1,144.8	1,324.1	1,495.4
Capital expenditure	242.6	267.9	273.5	275.8	279.4
Depreciation	76.6	86.0	94.2	104.4	113.2
Closing tax asset value	962.9	1,144.8	1,324.1	1,495.4	1,661.7

Table 16.4: Roll forward of taxation value of assets 1 January 2011 to 31 December 2015 ($m, nominal)

16.5 Taxable income

CitiPower's taxable income, for the purposes of clause 6.5.3 of the Rules, is calculated as:

- total building block revenue requirement;
- less building block operating and maintenance cost (inclusive of efficiency carryover and s factor true up);
- less benchmark interest cost;
- less tax depreciation; and
- less any brought forward tax losses.

16.6 Estimated cost of corporate income tax

The estimated cost of corporate income tax for the next regulatory control period is calculated based on the taxable income, in accordance with clause 6.5.3 of the Rules. The expected statutory income tax rate is 30 per cent and the assumed utilisation of imputation credits is 0.5, as discussed in Chapter 16 of this Regulatory Proposal.

Table 16.5 shows the estimated cost of corporate income tax.

	2011	2012	2013	2014	2015
Estimated cost of corporate income tax	10.5	11.3	11.3	11.8	13.2

Table 16.5: Estimated cost of corporate income tax ($m, nominal)

17. ANNUAL AND TOTAL REVENUE REQUIREMENTS AND X FACTORS FOR 2011-15

This Chapter details the calculation of CitiPower's proposed Annual Revenue Requirements, and X factors, for Standard Control Services for the each year of the next regulatory control period. It also details its proposed Total Revenue Requirement for the next regulatory control period.

17.1 Calculating the Annual Revenue Requirements

Clause 6.4.3 of the Rules requires the application of a building block approach to determine the Annual Revenue Requirements for Standard Control Services.

The building blocks are set out in clause 6.4.3(a) of the Rules and are:

- the indexation of the RAB;
- a return on capital;
- depreciation;
- the estimated cost of corporate income tax;
- revenue adjustments (if any) arising from the application of the Efficiency Benefit Sharing Scheme, the Service Target Performance Incentive Scheme, and the Demand Management Incentive Scheme; and
- other revenue adjustments (if any) arising from the application of the control mechanism in the previous regulatory control period; and
- forecast operating expenditure.

The development of each of these building blocks has been described in this Regulatory Proposal and is overviewed below.

17.1.1 Indexation of the RAB

Indexation of the RAB has been calculated using the AER's Post Tax Revenue Model. The Post Tax Revenue Model applies the forecast inflation rate to the annual opening nominal RAB to determine the indexation of the RAB.

Chapter 14 of this Regulatory Proposal sets out how the opening value of the RAB has been calculated and how it has been rolled forward within the 2011–15 regulatory control period, with annual adjustments for capital expenditure, depreciation, asset disposals and indexation.

Chapter 15 of this Regulatory Proposal sets out how the forecast inflation rate has been calculated.

The indexation of the RAB building block component derived from these two elements is summarised in Table 14.4.

17.1.2 Return on capital

Clause 6.5.2(a) of the Rules requires the return on capital for each regulatory year to be calculated by applying a rate of return to the value of the RAB as at the beginning of that regulatory year.

The return on capital building block has been calculated in accordance with clause 6.5.2(a) of the Rules using the AER's Post Tax Revenue Model. The Post Tax Revenue Model applies the nominal vanilla WACC to the annual opening nominal RAB to determine the return on capital.

Chapter 14 of this Regulatory Proposal sets out how the opening value of the RAB has been calculated and rolled forward within the 2011–15 regulatory control period, with annual adjustments for capital expenditure, depreciation, asset disposals and indexation.

Chapter 15 of this Regulatory Proposal sets out how the nominal vanilla WACC has been calculated.

The return on capital building block has been derived from these two elements and is summarised in Table 17.2.

17.1.3 Depreciation

The depreciation building block has been calculated in accordance with clause 6.5.5 of the Rules using the AER's Post Tax Revenue Model.

Chapter 13 of this Regulatory Proposal sets out how depreciation has been calculated.

The depreciation building block component is summarised in Table 13.2.

17.1.4 Estimated cost of corporate income tax

The depreciation building block has been calculated in accordance with clauses 6.5.3 and 11.17.2 of the Rules.

Chapter 16 of this Regulatory Proposal sets out how the cost of corporate income tax has been estimated.

The estimated cost of corporate income tax building block component is summarised in Table 17.2.

17.1.5 Revenue adjustments arising from the schemes

No revenue adjustments have been allowed for any revenue adjustments arising from the application of the Efficiency Benefit Sharing Scheme, the Service Target Performance Incentive Scheme, and the Demand Management Incentive Scheme in the next regulatory control period. The quantum of any such increments or decrements will not be known until the schemes are applied in the next regulatory control period.

17.1.6 Revenue adjustments arising from the current period

17.1.6.1 Efficiency benefit sharing scheme

Chapter 9 of this Regulatory Proposal discusses the efficiency carryover mechanism that applies in the current regulatory control period. The efficiency carryover mechanism revenue adjustment building block component is summarised in Table 9.2.

17.1.6.2 Service incentive mechanism

Chapter 10 of this Regulatory Proposal discusses the service incentive mechanism that applies in the current regulatory control period. On page 94 of its Framework and Approach Paper, the AER notes the following in relation to the current service incentive mechanism:

> *'the AER notes that benefits and penalties accrued in the current regulatory control period under the ESCV scheme will not be incorporated in the price cap formula. Rather, financial carryover amounts from the current regulatory control period will be included as a building block element in the calculation of allowed revenue for the next regulatory control period.'*

CitiPower has included a revenue adjustment in its Annual Revenue Requirements for the current service incentive mechanism, in accordance with clause 6.4.3(a)(5) of the Rules.

The current service incentive mechanism is set out in the 2006-10 EDPR. In summary, service performance in years t-2 and t-3 is used to calculate the S factor for year t. The S Factor for year t is applied to prices in year t and remains embedded in prices until the beginning of year t+6 when the equivalent S factor is removed from prices. The revenue increments or decrements from 2011 arising from prior service performance are shown in Table 17.1. The revenue increments and decrements arising in 2016 and 2017 have been discounted back to 2015 using a pre-tax WACC that is sourced from the Post Tax Revenue Model that is attached to this Regulatory Proposal.

	2011	2012	2013	2014	2015
Total	0.2	(2.7)	(3.1)	(0.1)	(6.3)

Table 17.1: Service target performance building blocks ($m, nominal)

Attachment C0086 is a spreadsheet which sets out how the service target performance building blocks have been calculated.

The revenue increments or decrements arising from service performance in 2008-09 are based on an estimate for 2009. The revenue increments or decrements arising from service performance in 2008-09 will be provided once actual performance data becomes available.

The revenue increments or decrements arising from service performance in 2009-10 are based on an estimate for 2010. Since the revenue increments or decrements arising from actual service performance in 2009-10 will not be known for the Final Distribution Determination, an s factor true up correction factor (t factor) is proposed to apply to the right hand side of the price control formula in 2012 (and remain embedded in prices to the end of 2015) to recover:

- the revenue increments or decrements arising from actual service performance in 2009-10; and
- the revenue increments or decrements arising from actual service performance in 2010 and the STPIS targets for 2011, but applying the current regulatory control period exclusion criteria. Since the 2011 STPIS targets are proposed to be based on average actual service performance over 2005-09, the 2011 STPIS targets for the purpose of the t factor calculation are proposed to be based on actual average service performance over 2005-09 applying the current regulatory control period exclusion criteria.

  This revenue adjustment is a necessary transitional adjustment to ensure that the performance incentive in 2010 is the same as that in any other year in the current regulatory control period as envisaged under the current service target performance scheme. In the absence of this revenue adjustment, any abnormal performance in 2010 would give rise to the NPV of annual revenue increments or decrements over the 2012-17 period. By contrast, any abnormal performance in 2009 (ie preceded by trend performance in 2008 and followed by trend performance in 2010) would give rise to the NPV of annual revenue increments or decrements over the 2011-16 period (arising from the 2008-09 performance difference) less the NPV of equivalent annual revenue increments or decrements over the 2012-17 period (arising from the 2009-10 performance difference). Clearly, the performance incentive in 2010, in the absence of the revenue adjustment, would be significantly greater than that in other years of the current regulatory control period.

For 2011 CitiPower has notionally banked all the increments arising from the current service incentive arrangement. This is consistent with the s banking arrangements under the current ESCV service incentive scheme.

CitiPower proposes that the t factor should be based on the model used to calculate the s factor true up for the Final Decision, which will be based on an estimate of service performance in 2010. That model should be rerun in 2011 inserting the 2010 actual service performance. This will result in true up amounts for 2012-15 which will be different to those applied in the buildings blocks for the Final Decision (the 2011 true up amount will not change because it is not dependent on 2010 service performance). The required correction ($) is the difference between the updated and Final Decision true up amounts for 2012-15.

The t factor that would need to be included in the price control (that is, as a further multiplicative factor) to effect the required price change, which would be the present value change in true up for 2012-15 divided by the present value of forecast revenue over the same period, where the discount rate is the pre tax WACC extracted from the Final Decision Post Tax Revenue Model.

This correction factor is based on a comparison of the correction and the revenue forecast over the entire 2012-15 period. Accordingly there is no need to add a further factor to remove the effect (rather, the intention is that prices be higher or lower by the required amount for the remainder of the period). The correction factor would be removed automatically at the 2016-20 EDPR as prices will, at that time, be realigned with costs.

17.1.7 Forecast operating expenditure

The operating expenditure building block has been calculated in accordance with clauses 6.5.6 and S6.1.2 of the Rules.

Chapter 6 of this Regulatory Proposal sets out how operating expenditure has been forecast.

CitiPower has not included its allowance under the DMIS as part of its forecast operating expenditure. It would expect the AER to include the allowance in its Final Decision.

The forecast operating expenditure building block component is summarised in Table 17.2.

17.2 Annual Revenue Requirements

The completed Post Tax Revenue Model provides the Annual Revenue Requirements, which comprise the sum of the components outlined in sections 17.1.1 to 17.1.7.

Table 17.2 summarises CitiPower's proposed Annual Revenue Requirements for the five years of the next regulatory control period.

Building block	2011	2012	2013	2014	2015
Indexation of the RAB	(31.6)	(36.0)	(40.9)	(46.0)	(51.1)
Return on capital	140.2	159.7	181.6	204.2	226.8
Depreciation	64.8	72.6	81.1	90.2	100.3
Operating expenditure	46.6	49.6	54.4	54.1	58.1
Corporate income tax	10.5	11.3	11.3	11.8	13.2
Efficiency carryover mechanism	0.0	0.0	0.0	0.0	0.0
Service incentive mechanism	0.2	(2.7)	(3.1)	(0.1)	(6.3)
Total	230.5	254.6	284.4	314.2	341.1

Table 17.2: Annual revenue requirement ($m, nominal)

17.3 Total Revenue Requirement

The Rules define the Total Revenue Requirement as:

> *'For a Distribution Network Service Provider, an amount representing revenue calculated for the whole of a regulatory control period in accordance with Part C of Chapter 6.'*

CitiPower has therefore calculated its proposed Total Revenue Requirement for the next regulatory control period as the summation of the Annual Revenue Requirements for each regulatory year of that regulatory control period. Clause 6.12.3(d) of the Rules provides that the AER must approve the Total Revenue Requirement set out in CitiPower's Building Block Proposal if it is satisfied that the amount has been properly calculated using the Post Tax Revenue Model on the basis of the amounts calculated, determined or forecast in accordance with the requirements of Part C of this Chapter 6 of the Rules.

On this basis, CitiPower's proposed Total Revenue Requirement for the next regulatory control period is $1,389 million.

17.4 X factors

Clause S6.1.3(6) of the Rules requires CitiPower's Building Block Proposal to include, amongst other things, the values of the X factors relevant to the calculation of revenues or prices for the purposes of the control mechanism proposed for the next regulatory control period. In accordance with clause 6.12.1(11) of the Rules, CitiPower is to determine the X factors in its Distribution Determination.

In 2009 CitiPower commenced an AMI roll out to upgrade all customers metering to remotely read interval meters. Having interval meters in place will allow for the development of efficient time of use network tariffs. Further, CitiPower is considering the development of demand based charging in the large customer segments using kVA rather than kW based demand measures. CitiPower is proposing to develop these network tariffs during 2010 for implementation in 2011.

CitiPower has utilised the formula in the AER's Post Tax Revenue Model to establish the proposed X factors for Standard Control Services in Table 17-3.

	2011	2012	2013	2014	2015
X factors (per cent)	(10.1)	(8.0)	(8.0)	(8.0)	(8.0)

Table 17.3: Proposed X factors (%)

In accordance with the weighted average price cap control mechanism that is to apply to its Standard Control Services, CitiPower has used forecast energy sales quantities to determine the proposed X factors. The energy sales quantities utilised to establish the X factors are based on the values in Chapter 4 of this Regulatory Proposal.

In accordance with clause 6.5.9(b) of the Rules, the X factors have been set:

- with regard to the proposed Total Revenue Requirement, in accordance with clause 6.5.9(b)(1) of the Rules;
- to minimise, as far as reasonably possible, the variance between expected revenue for the last regulatory year of the regulatory control period and the Annual Revenue Requirement for that last regulatory year, in accordance with clause 6.5.9(b)(2) of the Rules; and
- to equalise (in terms of net present value) the revenue to be earned from the provision of Standard Control Services over the regulatory control period with the Total Revenue Requirement for the regulatory control period, in accordance with clause 6.5.9(b)(3)(i) of the Rules.

18. CONTROL MECHANISM FOR STANDARD CONTROL SERVICES

This Chapter provides information in relation to CitiPower's control mechanism for Standard Control Services in accordance with the requirements of the Rules.

18.1 Rules' requirements

Clause 6.12.1 of the Rules details the constituent decisions that must be made by the AER as part of its Distribution Determination. The decisions that relate to the control mechanism for Standard Control Services are:

- a decision under clause 6.12.1(11) of the Rules on the control mechanism (including the X factor) for Standard Control Services (to be in accordance with the relevant framework and approach paper);
- a decision under clause 6.12.1(13) of the Rules on how compliance with a relevant control mechanism is to be demonstrated; and
- a decision under clause 6.12.1(19) of the Rules on how the DNSP is to report to the AER on its recovery of Transmission Use of System (**TUoS**) charges for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges.

18.2 Weighted average price cap control mechanism

The AER's Framework and Approach Paper provides that it will apply a weighted average price cap control mechanism to Standard Control Services in the next regulatory control period.

Appendix F of the Framework and Approach Paper details a formula to give effect to the weighted average price cap. It states that:

> 'The weighted average price cap distribution price control is expressed by the formula set out below.
>
> $$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}} \le (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)$$
>
> where a DNSP has *n distribution tariffs*, which each have up to *m distribution tariff components*, and where:
>
> > *regulatory year 't'* is the *regulatory year* in respect of which the calculation is being made;

regulatory year 't-1' is the *regulatory year* immediately preceding *regulatory year 't'*;

regulatory year 't-2' is the *regulatory year* immediately preceding *regulatory year 't-1'*;

p_t^{ij} is the proposed *distribution tariff* for component *j* of *distribution tariff i* in *regulatory year t* ;

p_{t-1}^{ij} is the *distribution tariff* being charged in *regulatory year t-1* for component *j* of *distribution tariff i;*

q_{t-2}^{ij} is the quantity of component *j* of *distribution tariff i* that was delivered in *regulatory year t-2*;

CPI_t is calculated as follows:

> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of *regulatory year t*;

divided by

> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of *regulatory year t-1*;

X to be determined using the building block approach;

S_t is the Service Target Performance Incentive Scheme factor to be applied in *regulatory year t*; and

L_t is the *licence fee* pass-through adjustment to be applied in *regulatory year t.*'

CitiPower supports the application of a weighted average price cap for Standard Control Services. However, CitiPower proposes that three clarifications be made to the AER's formula in relation to the licence fee factor, any approved cost pass-throughs and the s factor true up correction factor.

18.2.1 Calculation of the licence fee factor

Appendix F of the Framework and Approach Paper does not detail the basis on which the licence fee factor will be calculated in the weighted average price cap formula.

CitiPower proposes that the licence fee factor be calculated by using the formula that is currently provided for in clause 2.3.15 of Volume 2 of the ESCV's 2006-10 EDPR. This formula is detailed in Attachment C0141 of this Regulatory Proposal.

The application of this formula will result in there being no change to the current treatment of the licence fee factor in the next regulatory control period. It also promotes the requirement for the AER to have regard to 'the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination', as required by clause 6.2.5(c)(3) of the Rules.

18.2.2 Allowance for any approved cost pass-throughs

Appendix F of the AER's Framework and Approach Paper does not detail the basis on which approved cost pass-through amounts will be included in the weighted average price cap formula.

CitiPower proposes that the weighted average price cap formula be amended by including a provision for positive and negative cost pass-through amounts that have been approved by the AER.

The revised control mechanism formula would there be as follows:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}} \leq (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)\pm(pass\ through_t)$$

The new *'pass-through$_t$'* term represents the change in approved pass-through amounts, expressed in percentage form, with respect to regulatory year *'t'* as compared to regulatory year *'t-1'*, as determined by the AER under clause 6.6 of the Rules.

CitiPower notes that the AER included a pass-through term in the weighted average price cap for the NSW DNSPs in its April 2009 *Final decision - New South Wales distribution determination 2009–10 to 2013–14*.

Without the inclusion of a pass-through term in the control mechanism formula there is no explicit basis on which CitiPower could reflect any approved pass-through amounts into its prices.

18.3 t factor (S factor true up correction factor)

Section 17.1.6.2 of this Regulatory Proposal describes the calculation of the s factor true up correction factor (t factor) which would be included in the price control formula for 2012 as a further multiplier following the licence fee adjustment.

18.4 Side constraints

Clause 6.18.6 of the Rules establishes a side constraint on the annual movement of tariffs for Standard Control Services. This serves to limit the expected increase in the weighted average revenue to be raised from a tariff class from a DNSP's tariff rebalancing.

CitiPower recognises that the calculation of the permissible change in weighted average revenue must comply with clause 6.18.6 of the Rules.

18.5 Allowing for tariff changes

There is a need to specify how the weighted average price cap will accommodate the introduction of new tariffs or tariff components and adjustments to existing tariffs or tariff components.

CitiPower proposes that the current arrangements that apply to it under clause 2.2.5 to 2.2.8 of Volume 2 of the ESCV's 2006-10 EDPR continue to apply in the next regulatory control period. These provisions are detailed in Attachment C0141 of this Regulatory Proposal.

The application of this arrangement will result in there being no change to the current treatment of tariff changes in the next regulatory control period. It also promotes the requirement for the AER to have regard to *'the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination'*, as required by clause 6.2.5(c)(3) of the Rules.

18.6 Recovery of transmission use of system charges

Clause 6.12.1(19) of the Rules requires the AER's Distribution Determination to include a decision on how CitiPower is to report to the AER on its TUoS charges for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges.

CitiPower will continue to be required to pay TUoS charges throughout the 2011-15 regulatory control period. These charges will be recovered from retailers in addition to DUoS charges for the use of CitiPower's distribution network.

The AER's Framework and Approach Paper does not detail the basis on which CitiPower can recover TUoS charges.

CitiPower proposes that the arrangements in Chapter 3 of Volume 2 of the ESCV's 2006-10 EDPR continue to be applied in the next regulatory control period. These arrangements are detailed in Attachment C0141 of this Regulatory Proposal.

CitiPower notes that the TUoS formula in clause 3.3 of Volume 2 of the ESCV's 2006-10 EDPR includes an unders and overs mechanism to enable it to deal with the inevitable effect of volume variations on actual and expected revenue in any regulatory year. Inevitably, volume uncertainties will lead to some residual over or under recovery of TUoS charges at the end of the current determination. CitiPower proposes that any under or over recovered amount would be carried through to the 2011-15 determination using a continuation of the process detailed in Attachment C0141 of this Regulatory Proposal.

The application of this TUoS formula will result in there being no change to the current treatment of the recovery of TUoS charges in the next regulatory control period. It also promotes the requirement for the AER to have regard to *'the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination'*, as required by clause 6.2.5(c)(3) of the Rules.

18.7 Embedded generation and other fees

CitiPower will be required to make payments for:

- avoided TUoS charges to embedded generators, under clause 5.5(h)-(j) of the Rules;
- feed-in tariffs for the excess energy that customers with photovoltaic generation export to the grid and related operational costs. The *Electricity Industry Act 2000* has stipulated that this payment is to be treated as a pass-through for the current regulatory control period. The Act does not specify how payments for feed-in tariffs are to be treated in the next regulatory control period; and
- avoided DUoS payments made to embedded generators where support arrangements are negotiated.

The AER's Framework and Approach Paper does not detail the basis on which CitiPower can recover the costs of meeting these obligations.

CitiPower proposes that these payments be recovered through the G component of the control mechanism in clause 3.3.4 of Volume 2 of the ESCV's 2006-10 EDPR.

18.8 Inter DNSP charges

In certain areas, it is more economic to supply customers from supply points from neighbouring DNSPs than to build new assets. In these cases, the neighbouring DNSP will charge CitiPower for the energy flows associated with supplying the customer.

These flows of energy are of a similar nature to transmission supply, as they provide for electricity flow into (or out of) the DNSP's distribution system. The payments for inter distribution business charges should also be treated the same way as transmission charges in that, whereby energy that flows through the grid is not brought to account as distribution revenue, then it should be treated as a pass-through cost (revenue).

CitiPower proposes that these charges be recovered through the D component of the control mechanism in clause 3.3.4 of Volume 2 of the ESCV's 2006-10 EDPR. As noted above, CitiPower proposes that the arrangements in Chapter 3 of Volume 2 of the ESCV's 2006-10 EDPR continue to apply in the next regulatory control period. These are detailed in Attachment C0141of this Regulatory Proposal.

The result of the application of this process will be that CitiPower will only claim the costs/revenues that are not otherwise recovered through DUOS charges. This will ensure that there is no double recovery of DUOS costs / revenue.

19. PRICING FOR STANDARD CONTROL SERVICES

This Chapter provides information in relation to CitiPower's indicative prices for Standard Control Services in accordance with the requirements of the Rules.

19.1 Rules' requirements

Clause 6.8.2(c)(4) of the Rules requires CitiPower to include in this Regulatory Proposal indicative prices for Direct Control Services for each year of the next regulatory control period.

Clause 6.12.1(17) of the Rules requires the AER's Distribution Determination to include a decision on the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another (including any applicable restrictions).

Importantly, this Chapter does not represent CitiPower's Pricing Proposal for the next regulatory control period and the indicative prices are not the prices that CitiPower proposes charging customers. CitiPower will submit its initial Pricing Proposal to the AER in accordance with clause 6.18.2(a)(1) of the Rules *'as soon as practicable, and in any case within 15 business days, after publication of the distribution determination........for the first regulatory year of the regulatory control period'*.

19.2 Tariff reforms

CitiPower proposes introducing two major network tariff initiatives in the next regulatory control period.

Firstly, significant network tariff reform has become possible with the rolling out of AMI. The interval data that is supplied by AMI meters will allow CitiPower to introduce pricing structures in order to seek to promote more effective price signals.

Secondly, CitiPower is considering reforms to its large customer network tariffs by introducing reactive demand (**kVA**) based charging for new customers. The benefit of moving to this form of capacity charging is that it is more reflective of the asset costs required to deliver electricity to these customers. This initiative will be further developed through 2010.

The key driver for these reforms is the delivery of more efficient price signals to customers.

19.3 Tariff classes

The five network tariff classes that CitiPower proposes to use in the next regulatory control period are as follows:

- residential;

- small/medium business;
- large low voltage (**LLV**);
- high voltage (**HV**); and
- sub transmission.

These tariff classes are sufficiently broad to ensure that all of the existing customers are assigned to their appropriate tariff class. Very few customers are expected to seek to be reclassified to a different tariff class during the course of the next regulatory control period.

Within each tariff class, there has been, and will continue to be, movement between individual tariffs. This is particularly the case with the low voltage business customers. Customers are eligible to apply for transfer between tariffs and do so if it is to their advantage.

CitiPower considers that it is critical to preserve the flexibility to allow customers to transfer to a more appropriate tariff in order to meet their ongoing needs and expectations.

19.4 Tariff class assignment for new and upgraded customer connections

During the current regulatory control period, CitiPower has established a tariff assignment policy in order to accommodate the rollout of manually read interval meters (**MRIM**) meters.

Appendix A of the AER's April 2009 *Final decision - New South Wales distribution determination 2009–10 to 2013–14* sets out a procedure for the review of tariff class assignments. CitiPower considers that this procedure is largely appropriate for its circumstances[78]. The AER nominated the Energy and Water Ombudsman of NSW as the organisation to which a small retail customer may refer an objection to a tariff class assignment or reassignment. The equivalent body in Victoria is the Energy and Water Ombudsman (Victoria).

19.5 Indicative prices for Standard Control Services

Clause 6.8.2(c)(4) of the Rules requires CitiPower to detail its '*indicative prices for each year of the next regulatory control period*' for its Standard Control Services.

CitiPower sets out its proposed distribution tariffs for the 2010 regulatory control year in Table 19-1. CitiPower considers that the best guide to its prices for Standard Control Services for each year of the next regulatory control period is the equivalent 2010 proposed distribution tariffs set out below in Table 19-1 escalated by CPI-X.

[78] Final decision—New South Wales distribution determination 2009–10 to 2013–14, AER, 28 April 2009, Appendix A, pp409–410

As the proposed network tariffs have not been approved at the time of submitting this Regulatory Proposal, CitiPower is proposing, for the purposes of calculating the P_0 and X factors in the PTRM, to develop notional 2010 time of use network tariffs. These network tariffs have been calculated on the basis that the net present value of the 2011-15 forecast revenue with the new network tariffs is equal to the net present value of the 2011-15 forecast revenue without the new network tariffs. The 2010 approved network tariffs are unchanged for the purposes of calculating the P_0 and X factors in the PTRM.

DISTRIBUTION TARIFF SCHEDULE

(GST EXCLUSIVE)

1 JANUARY 2010 – 31 DECEMBER 2010

DUoS Tariff	Code	Available to new customers?	Standing charges $/cust/pa	Demand charges $/kW/pa	Demand charges $/kvA/pa	Minimum Demand	Peak charges (c/kWh)		Off peak charges c/kWh
							First 340 kWh/month	Balance	
Residential Single Rate	C1R	Yes	16.081				4.014	5.531	
Residential Single Rate - Bulk	C1RB	Yes	13.867				3.244	4.328	
Residential Two Rate 5d	C2R	Yes	35.903				7.235	6.890	0.706
Residential Two Rate 5d - Bulk	C2RB	Yes	35.394				5.694	5.423	0.603
Residential Interval	C3R	Yes	35.903				7.235	6.890	0.706
Residential Interval - Bulk	C3RB	Yes	35.394				5.694	5.423	0.603
Dedicated Circuit	CDS	No							0.811
Dedicated Circuit - Bulk	CDSB	No							0.711
Non-Residential Single Rate	C1G	Yes	36.221				4.721	4.970	
Non-Residential Single Rate - Bulk	C1GB	Yes	30.893				3.770	3.969	
Non-Residential Two Rate 5d	C2G5	Yes	86.021				6.489	6.180	1.289
Non-Residential Two Rate 5d - Bulk	C2G5B	Yes	80.200				4.910	4.676	0.962
Non-Residential Interval	C3G	Yes	86.021				6.489	6.180	1.289
Non-Residential Interval - Bulk	C3GB	Yes	80.200				4.910	4.676	0.962
Non-Residential Two Rate 7d	C2G7	No	78.126			-	4.653	4.950	1.193
Non-Residential Two Rate 7d - Bulk	C2G7B	No	71.857			-	3.613	3.844	0.910
Unmetered Supplies	C2U	Yes				-	5.813	5.813	1.393
Large Two Rate 7d	C2L7	No	75.265			-	4.231	4.231	1.231
Large Low Voltage Demand	C2DL	Yes		59.925		120	1.042	1.042	1.044
Large Low Voltage Demand - Bulk	C2DLB	Yes		54.824		120	0.603	0.603	0.957
Large Low Voltage Demand R	C2DLER	Yes		64.248		120	1.113	1.113	1.138
Large Low Voltage Demand G	C2DLEG	Yes		64.248		120	1.113	1.113	1.138
Large Low Voltage Demand - Bulk R	C2DLBER	Yes		58.778		120	0.645	0.645	1.045
Large Low Voltage Demand - Bulk G	C2DLBEG	Yes		58.778		120	0.645	0.645	1.045
High Voltage Demand	C2DH	Yes		38.941		1,000	0.293	0.293	0.430
High Voltage Demand D1	C2DHD1	No		24.450		40,000	0.073	0.073	0.067
High Voltage Demand R	C2DHER	Yes		41.750		1,000	0.316	0.316	0.474
High Voltage Demand G	C2DHEG	Yes		41.750		1,000	0.316	0.316	0.474
Subtransmission Demand	C2DT	Yes		9.002		10,000	0.091	0.091	0.135

TRANSMISSION TARIFF SCHEDULE
(GST EXCLUSIVE)
1 JANUARY 2010 – 31 DECEMBER 2010

TUoS Tariff	Code	Available to new customers?	Standing charges $/cust/pa	Demand charges $/kW/pa	Demand charges $/kvA/pa	Minimum Demand	Peak charges (c/kWh)		Off peak charges c/kWh
							First 340 kWh/month	Balance	
Residential Single Rate	C1R	Yes	4.276				0.842	0.842	
Residential Single Rate - Bulk	C1RB	Yes	3.073				0.702	0.702	
Residential Two Rate 5d	C2R	Yes	8.449				1.122	1.122	0.606
Residential Two Rate 5d - Bulk	C2RB	Yes	6.286				0.887	0.887	0.610
Residential Interval	C3R	Yes	8.449				1.122	1.122	0.606
Residential Interval - Bulk	C3RB	Yes	6.286				0.887	0.887	0.610
Dedicated Circuit	CDS	No							0.489
Dedicated Circuit - Bulk	CDSB	No							0.497
Non-Residential Single Rate	C1G	Yes	9.442				1.149	1.149	
Non-Residential Single Rate - Bulk	C1GB	Yes	6.711				0.980	0.980	
Non-Residential Two Rate 5d	C2G5	Yes	22.421				1.616	1.616	0.497
Non-Residential Two Rate 5d - Bulk	C2G5B	Yes	17.420				1.366	1.366	0.414
Non-Residential Interval	C3G	Yes	22.421				1.616	1.616	0.497
Non-Residential Interval - Bulk	C3GB	Yes	17.420				1.366	1.366	0.414
Non-Residential Two Rate 7d	C2G7	No	20.325			-	1.325	1.325	0.497
Non-Residential Two Rate 7d - Bulk	C2G7B	No	15.593			-	1.124	1.124	0.414
Unmetered Supplies	C2U	Yes				-	0.431	0.431	0.420
Large Two Rate 7d	C2L7	No	21.853			-	2.253	2.253	0.544
Large Low Voltage Demand	C2DL	Yes		9.518		120	1.492	1.492	0.544
Large Low Voltage Demand - Bulk	C2DLB	Yes		9.446		120	1.481	1.481	0.539
Large Low Voltage Demand R	C2DLER	Yes		9.815		120	1.548	1.548	0.565
Large Low Voltage Demand G	C2DLEG	Yes		9.815		120	1.548	1.548	0.565
Large Low Voltage Demand - Bulk R	C2DLBER	Yes		9.740		120	1.539	1.539	0.560
Large Low Voltage Demand - Bulk G	C2DLBEG	Yes		9.740		120	1.539	1.539	0.560
High Voltage Demand	C2DH	Yes		7.535		1,000	1.539	1.539	0.507
High Voltage Demand D1	C2DHD1	No		10.106		40,000	1.419	1.419	0.710
High Voltage Demand R	C2DHER	Yes		7.769		1,000	1.597	1.597	0.527
High Voltage Demand G	C2DHEG	Yes		7.769		1,000	1.597	1.597	0.527
Subtransmission Demand	C2DT	Yes		3.166		10,000	1.794	1.794	0.521

PREMIUM FEED IN TARIFF FEE
(GST EXCLUSIVE)
1 JANUARY 2010 – 31 DECEMBER 2010

PFIT Tariff	Code	Available to new customers?	Standing charges $/cust/pa	Demand charges $/kW/pa	Demand charges $/kvA/pa	Minimum Demand	Peak charges (c/kWh)		Off peak charges c/kWh
							First 340 kWh/month	Balance	
Residential Single Rate	C1R	Yes	1.107						
Residential Single Rate - Bulk	C1RB	Yes	1.107						
Residential Two Rate 5d	C2R	Yes	1.107						
Residential Two Rate 5d - Bulk	C2RB	Yes	1.107						
Residential Interval	C3R	Yes	1.107						
Residential Interval - Bulk	C3RB	Yes	1.107						
Dedicated Circuit	CDS	No							
Dedicated Circuit - Bulk	CDSB	No							
Non-Residential Single Rate	C1G	Yes	1.107						
Non-Residential Single Rate - Bulk	C1GB	Yes	1.107						
Non-Residential Two Rate 5d	C2G5	Yes	1.107						
Non-Residential Two Rate 5d - Bulk	C2G5B	Yes	1.107						
Non-Residential Interval	C3G	Yes	1.107						
Non-Residential Interval - Bulk	C3GB	Yes	1.107						
Non-Residential Two Rate 7d	C2G7	No	1.107						
Non-Residential Two Rate 7d - Bulk	C2G7B	No	1.107						
Unmetered Supplies	C2U	Yes							
Large Two Rate 7d	C2L7	No							
Large Low Voltage Demand	C2DL	Yes		0.381		120			
Large Low Voltage Demand - Bulk	C2DLB	Yes		0.381		120			
Large Low Voltage Demand R	C2DLER	Yes		0.381		120			
Large Low Voltage Demand G	C2DLEG	Yes		0.381		120			
Large Low Voltage Demand - Bulk R	C2DLBER	Yes		0.381		120			
Large Low Voltage Demand - Bulk G	C2DLBEG	Yes		0.381		120			
High Voltage Demand	C2DH	Yes		0.381		1000			
High Voltage Demand D1	C2DHD1	No		0.381		40000			
High Voltage Demand R	C2DHER	Yes		0.381		1000			
High Voltage Demand G	C2DHEG	Yes		0.381		1000			
Subtransmission Demand	C2DT	Yes		0.381		10000			

NETWORK TARIFF SCHEDULE
(GST EXCLUSIVE)
1 JANUARY 2010 – 31 DECEMBER 2010

NIUoS Tariff (Incl PFIT Fee)	Code	Available to new customers?	Standing charges $/cust/pa	Demand charges $/kW/pa	Demand charges $/kvA/pa	Minimum Demand	Peak charges (c/kWh)		Off peak charges c/kWh
							First 340 kWh/month	Balance	
Residential Single Rate	C1R	Yes	21.464				4.856	6.373	
Residential Single Rate - Bulk	C1RB	Yes	18.047				3.946	5.03	
Residential Two Rate 5d	C2R	Yes	45.459				8.357	8.012	1.312
Residential Two Rate 5d - Bulk	C2RB	Yes	42.787				6.581	6.31	1.213
Residential Interval	C3R	Yes	45.459				8.357	8.012	1.312
Residential Interval - Bulk	C3RB	Yes	42.787				6.581	6.31	1.213
Dedicated Circuit	CDS	No							1.3
Dedicated Circuit - Bulk	CDSB	No							1.208
Non-Residential Single Rate	C1G	Yes	46.77				5.87	6.119	
Non-Residential Single Rate - Bulk	C1GB	Yes	38.711				4.75	4.949	
Non-Residential Two Rate 5d	C2G5	Yes	109.549				8.105	7.796	1.786
Non-Residential Two Rate 5d - Bulk	C2G5B	Yes	98.727				6.276	6.042	1.376
Non-Residential Interval	C3G	Yes	109.549				8.105	7.796	1.786
Non-Residential Interval - Bulk	C3GB	Yes	98.727				6.276	6.042	1.376
Non-Residential Two Rate 7d	C2G7	No	99.558				5.978	6.275	1.69
Non-Residential Two Rate 7d - Bulk	C2G7B	No	88.557				4.737	4.968	1.324
Unmetered Supplies	C2U	Yes					6.244	6.244	1.813
Large Two Rate 7d	C2L7	No	97.118				6.484	6.484	1.775
Large Low Voltage Demand	C2DL	Yes		69.824		120	2.534	2.534	1.588
Large Low Voltage Demand - Bulk	C2DLB	Yes		64.651		120	2.084	2.084	1.496
Large Low Voltage Demand R	C2DLER	Yes		74.444		120	2.661	2.661	1.703
Large Low Voltage Demand G	C2DLEG	Yes		74.444		120	2.661	2.661	1.703
Large Low Voltage Demand - Bulk R	C2DLBER	Yes		68.899		120	2.184	2.184	1.605
Large Low Voltage Demand - Bulk G	C2DLBEG	Yes		68.899		120	2.184	2.184	1.605
High Voltage Demand	C2DH	Yes		46.857		1000	1.832	1.832	0.937
High Voltage Demand D1	C2DHD1	No		34.937		40000	1.492	1.492	0.777
High Voltage Demand R	C2DHER	Yes		49.9		1000	1.913	1.913	1.001
High Voltage Demand G	C2DHEG	Yes		49.9		1000	1.913	1.913	1.001
Subtransmission Demand	C2DT	Yes		12.549		10000	1.885	1.885	0.656

PRESCRIBED METERING SERVICE TARIFF SCHEDULE
(GST EXCLUSIVE)
1 JANUARY 2010 – 31 DECEMBER 2010

Prescribed metering Service Tariff	$/NMI/pa	$/light/pa
Metering charge - single phase	104.790	
Metering charge - multi phase - direct connected (DC)	136.980	
Metering charge - multi phase - current transformer (CT)	172.990	
Metering data service - unmetered supplies		1.155

ADDITIONAL TERMS

The same charge applies to interval and accumulation meters where customers consume less than 160MWh/pa.

EMBEDDED GENERATION TARIFF SCHEDULE
(GST EXCLUSIVE)
1 JANUARY 2010 – 31 DECEMBER 2010

Embedded Generaiton	c/kWh
Premium feed-in tariff	-60.000

ADDITIONAL TERMS

The customer must have a qualifying PV generation facility and have accepted a retailer offer to receive the premium feed-in tariff.

CBD SECURITY OF SUPPLY LEVY
(GST EXCLUSIVE)
1 JANUARY 2010 – 31 DECEMBER 2010

			Demand charges	Peak charges		Off Peak charges
Network Tariffs	Network Tariff Category	Standing charges	kW	Block1	Block 2	Block 1
		$/cust pa	$/kW pa	c/kWh	c/kWh	c/kWh
Residential Single Rate	C1R	0.123	-	0.030	0.041	-
Residential Single Rate - Bulk	C1RB	0.106	-	0.025	0.031	-
Residential Two Rate 5d	C2R	0.274	-	0.051	0.051	0.005
Residential Two Rate 5d - Bulk	C2RB	0.271	-	0.040	0.040	0.004
Residential Interval	C3R	0.274	-	0.051	0.051	0.005
Residential Interval - Bulk	C3RB	0.271	-	0.040	0.040	0.004
Dedicated Circuit	CDS	-	-	-	-	0.006
Dedicated Circuit - Bulk	CDSB	-	-	-	-	0.005
Non-Residential Single Rate	C1G	0.277	-	0.038	0.038	-
Non-Residential Single Rate - Bulk	C1GB	0.235	-	0.030	0.030	-
Non-Residential Two Rate 5d	C2G5	0.658	-	0.046	0.046	0.010
Non-Residential Two Rate 5d - Bulk	C2G5B	0.613	-	0.036	0.036	0.007
Non-Residential Interval	C3G	0.658	-	0.046	0.046	0.010
Non-Residential Interval - Bulk	C3GB	0.613	-	0.036	0.036	0.007
Non-Residential Two Rate 7d	C2G7	0.597	-	0.038	0.038	0.010
Non-Residential Two Rate 7d - Bulk	C2G7B	0.549	-	0.029	0.029	0.007
Unmetered Supplies	C2U	-	-	0.044	0.044	0.010
Large Two Rate 7d	C2L7	0.576	-	0.031	0.031	0.009
Large Low Voltage Demand	C2DL	-	0.458	0.007	0.007	0.008
Large Low Voltage Demand - Bulk	C2DLB	-	0.418	0.004	0.004	0.007
Large Low Voltage Demand R	C2DLER	-	0.491	0.008	0.008	0.008
Large Low Voltage Demand G	C2DLEG	-	0.491	0.008	0.008	0.008
Large Low Voltage Demand - Bulk R	C2DLBER	-	0.449	0.005	0.004	0.008
Large Low Voltage Demand - Bulk G	C2DLBEG	-	0.449	0.005	0.004	0.008
High Voltage Demand	C2DH	-	0.297	0.002	0.002	0.003
High Voltage Demand D1	C2DHD1	-	0.187	0.001	0.001	-
High Voltage Demand R	C2DHER	-	0.318	0.002	0.002	0.003
High Voltage Demand G	C2DHEG	-	0.318	0.002	0.002	0.003
Subtransmission Demand	C2DT	-	0.069	0.001	0.001	0.001

CBD SECURITY OF SUPPLY LEVY
(GST EXCLUSIVE)
1 JANUARY 2010 – 31 DECEMBER 2010

20. MODELS

This chapter provides information in relation to CitiPower's completed Post Tax Revenue Model and Roll Forward Model.

CitiPower confirms that it has:

- prepared its Building Block Proposal in accordance with the Post Tax Revenue Model, as required by clause 6.3.1(c)(1) of the Rules;
- calculated its RAB using a Roll Forward Model that it has prepared, as required by clause S6.1.3(7) of the Rules;
- provided a completed Post Tax Revenue Model to the AER as part of this Building Block Proposal that shows its application to CitiPower, as required by clause S6.1.3(10) of the Rules;
- provided a completed Roll Forward Model to the AER as part of its Building Block Proposal, as required by clause S6.1.3(10) of the Rules; and
- provided a completed version of the AER's public lighting model.

21. TRANSITIONAL MATTERS

Paragraph 14 of the RIN requires CitiPower to identify, and provide certain information in relation to, all *'transitional matters'* which will arise in transitioning from economic regulation under the ESCV to economic regulation under the AER. *'Transitional matters'* are defined in the RIN to mean *'an issue having a material impact on [CitiPower] which arises from the transition from the current regulatory control period* to the *forthcoming regulatory control period'*.

CitiPower observes that the process of identifying and explaining *'transitional matters'* necessarily requires it to form a view as to the legal position in respect of economic regulation under the ESCV's 2006-10 EDPR vis-à-vis the legal position in respect of economic regulation under the NEL/NER. Consequently, CitiPower queries whether the AER is empowered by the NEL to require CitiPower to provide to it the details requested in paragraph 14. Specifically, CitiPower observes the following:

- section 28D(a) of the NEL indicates that a *'regulatory information notice'* means a notice *'that requires the regulated network service provider … to provide to the AER the information specified in the notice'*. The NEL does not permit the AER to require the provision to it of anything other than *'information'*;
- *'information'* is not defined in the NEL, but is defined in the Macquarie Dictionary as *'knowledge communicated or received concerning some fact or circumstance';*
- CitiPower considers, therefore, that the NEL provides for the AER to request the provision of knowledge with respect to questions of fact, but not questions of law; and
- given the process of identifying and explaining *'transitional matters'* necessarily involves the consideration of questions of law, CitiPower queries whether the AER is permitted by the NEL to request such details.

However, while reserving its rights in relation to the validity of the AER's RIN in this regard, CitiPower has endeavoured to comply with the requirements of paragraph 14 of the RIN.

As the AER would be aware, by reason of section 28T of the NEL, a regulatory information instrument (such as the AER's RIN) is not to be taken to as requiring a person to:

- provide to the AER information that is the subject of legal professional privilege; or
- produce a document to the AER the production of which would disclose information that is the subject of legal professional privilege.

Accordingly, to the extent it is valid, the obligations in paragraph 14 of the RIN to identify and explain all *'transitional matters'* are not to be taken as requiring CitiPower to disclose information that is the subject of professional legal privilege. CitiPower does not include such information in this Regulatory Proposal.

Nonetheless, subject to legal professional privilege, CitiPower observes that the following matters will have a material impact on CitiPower as it moves from regulation under the ESCV to regulation under the AER:

- transitional issue arising as a result of differences between the definition MAIFI parameter of the reliability component of the AER's STPIS and the analogous component of the ESCV's service incentive scheme (described in section 10.1.2 of this Regulatory Proposal);
- transitional matter arising from the shifting from the ESCV' service incentive scheme to the AER's STPIS arrangements; and
- transitional matters arising in relation to the EBSS and the calculation of carryover over amounts from the current regulatory control period and the possible carryover of accrued carryover amounts from the previous regulatory control (described in sections 9.6 and 9.7 of this Regulatory Proposal).

CitiPower may be financially impacted if the AER maintains the definition of MAIFI as per the STPIS. This is because the current definition of MAIFI, applicable to Victorian DNSPs, is inconsistent with the definition outlined in the STPIS. CitiPower does not have the data to recalculate its historical MAIFI performance based on the STPIS definition hence may be disadvantaged financially through a MAIFI target established on a different basis to that on which performance is being measured. A fuller discussion is presented in section 10.1.2 of this Regulatory Proposal.

Differences between the service incentive scheme operated by the ESCV and that set out by the AER in its STPIS give rise to windfall financial gains/losses depending on a DNSP's outturn performance over the current regulatory control period. CitiPower has sought to address this issue through the t factor outlined in section 17.1.6.2 of this Regulatory Proposal.

Transitional matters arise in relation to the EBSS and the calculation of carryover over amounts from the current regulatory control period and the possible carryover of accrued carryover amounts from the previous regulatory control. These transitional matters are explained in sections 9.6 and 9.7 of this Regulatory Proposal. These transitional matters may impact CitiPower by affecting its revenue requirement for the following regulatory control period by virtue of the application of carryover gains or losses. The financial impact is currently uncertain as it will depend on the approach that the AER takes to the matters addressed in sections 9.6 and 9.7 of this Regulatory Proposal. If the AER addresses these transitional matters as proposed by CitiPower in sections 9.6 and 9.7 of this Regulatory Proposal, these transitional matters will have no impact on service performance.

22. OTHER ENTITIES

This Chapter provides information in relation to CitiPower's service provision model and addresses the requirements of paragraph 6 of the AER's RIN.

22.1 CitiPower's service provision model

CitiPower's service provision model has evolved over time to enable it to better focus on its long term asset ownership and performance.

22.1.1 Relationship between CitiPower and other entities

For the purposes of paragraph 6.1(a) of the RIN, CitiPower confirms that the following entities are related parties as defined in the RIN and contribute to the provision of distribution services:

- CHED Services Pty Ltd (ACN 112 304 622) (**CHED Services**) provides services to CitiPower (and other clients) under a Corporate Services Agreement;
- Powercor Network Services Pty Ltd (ACN 123 230 24) (**PNS**) provides network services to CitiPower (and other clients) under a Network Services Agreement;
- Silk Telecom Pty Ltd (ACN 095 420 616) (**Silk Telecom**); and
- Powercor Australia Ltd (ACN 064 651 109) (**Powercor Australia**).

The RIN expressly defines *'related party'* to include Silk Telecom Pty Ltd (ACN 095 420 616) and, accordingly, CitiPower includes Silk Telecom in the above list. However, CitiPower argues that Silk Telecom does not currently satisfy any of the generic criteria for a *'related party'* listed in the '*related party*' definition in the RIN. Silk Telecom was sold in 2008 to Nextgen Networks. As a result of the sale, Silk Telecom/Nextgen is no longer a 'related party' for the purposes of the criteria listed in the RIN definition of *'related party'*. Silk Telecom/Nextgen Networks does, however, contribute to the provision of telecommunication and related services.

CitiPower considers that Powercor Australia satisfies the generic criteria for a *'related party'* listed in the *'related party'* definition in the RIN. CitiPower may be said to contribute to the provision of distribution services insofar as it shares certain overhead costs with Powercor Australia pursuant to the Cost Sharing Agreement discussed below.

The following entities are also related parties as defined in the RIN but do not contribute to the provision of distribution services and, accordingly, do not appear in the list of entities for the purposes of paragraph 6.1(a) of the RIN set out above:

- CKI/HEH Electricity Distribution Holdings (Australia) Pty Ltd (ACN 101 392 161).
- CKI/HEI Electricity Distribution Pty Ltd (ACN 093 830 632) and each of its subsidiaries;

- CKI/HEI Electricity Distribution Two Pty Ltd (ACN 101 064 304) and each of its subsidiaries including the trustees of The CitiPower Trust.

For the purposes of paragraph 6.1(b) of the RIN, CitiPower confirms that none of the entities identified as related parties that contribute to the provision of distribution services have the capacity to determine the outcome of decisions about CitiPower's financial and operating policies.

No other entities have the capacity to determine the outcome of decisions about CitiPower's financial and operating policies.

For the purposes of paragraph 6.2 of the RIN, the two figures below provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to paragraph 6.1, with the exception of Silk Telecom. Silk Telecom does not appear in these figure because, as discussed above, Silk Telecom is not a related body corporate of CitiPower.

Figure 22-1 provides a diagram which illustrates the simplified group structure.

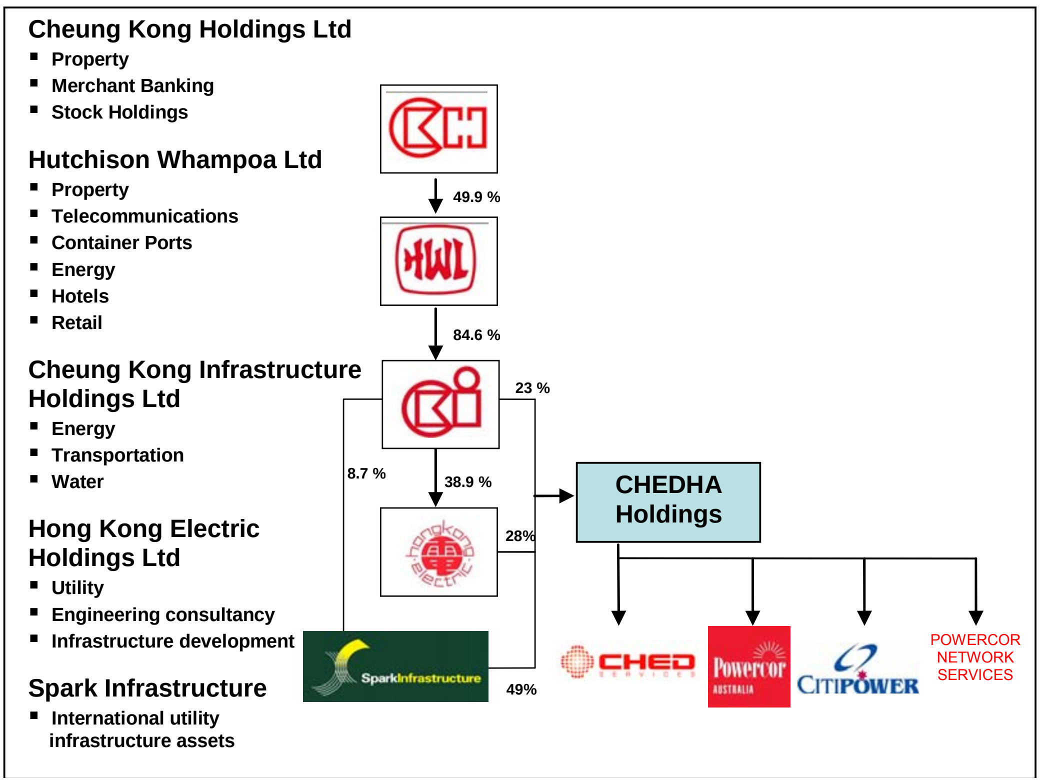

Figure 22-1 Group structure

Figure 22-2 provides a diagram which illustrates the CHEDHA Holdings group structure.

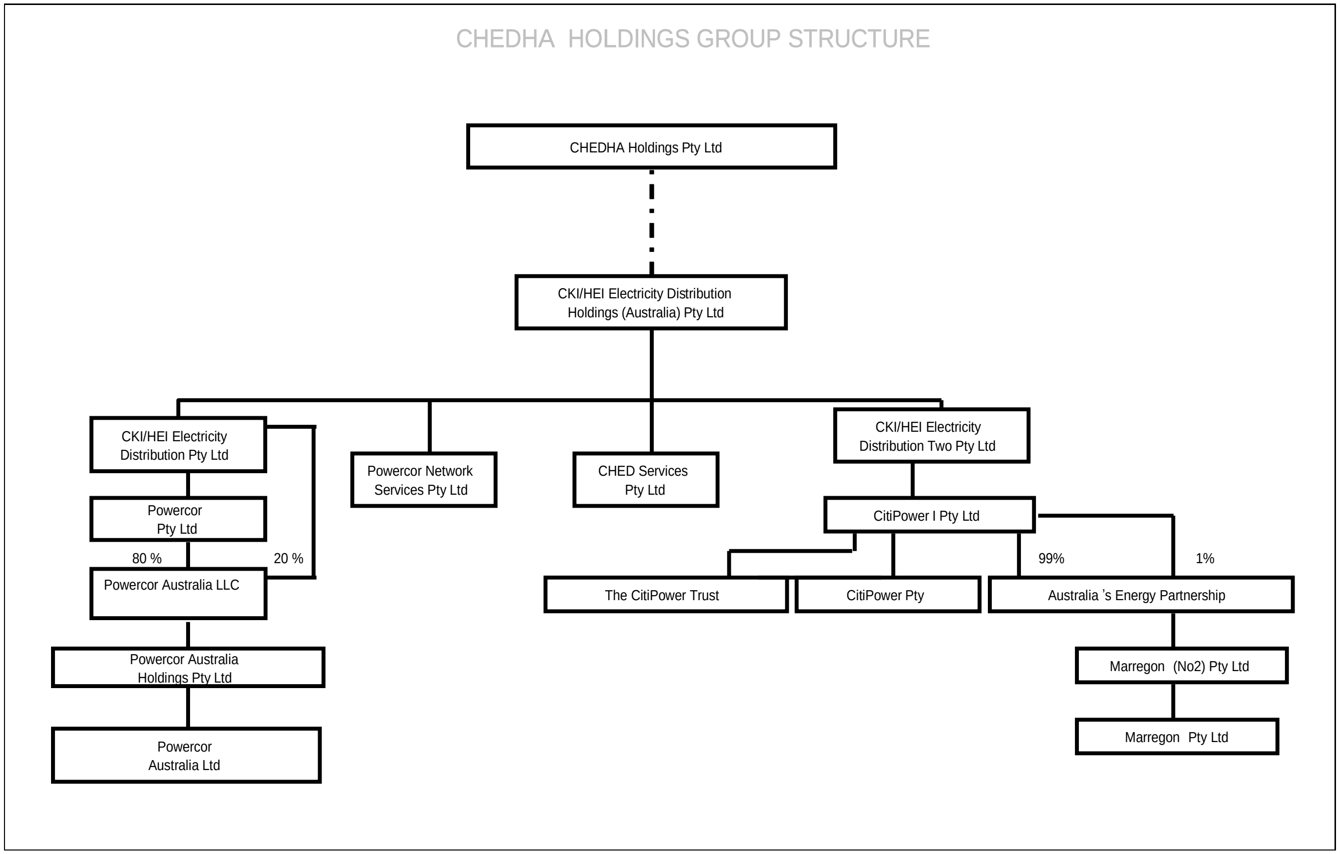

Figure 22-2 : The current CHEDA Holdings Group Structure

22.1.2 Evolution of service provision model

In response to paragraph 6.3 of the RIN, this section provides a description of the services provided by the related parties to CitiPower.

Prior to 30 August 2002, CitiPower and Powercor Australia were separately owned legal entities. Cheung Kong Infrastructure Ltd (**CKI**) and Hong Kong Electric Holdings Ltd (**HEH**) acquired Powercor Australia in 2000 and CitiPower in 2002. In 2005, CKI/HEH effectively listed 49 per cent of the equity in Powercor Australia and CitiPower on the Australian Stock Exchange (**ASX**) via Spark Infrastructure.

Upon the acquisition of CitiPower in 2002, CKI/HEH Electricity Distribution Holdings (Australia) Pty Ltd (**CHEDHA**) was created as a holding company for the CitiPower and Powercor Australia investments.

CHED Services

In 2005, a separate legal entity, CHED Services, was created and separated from CitiPower to provide specialist corporate services under the *Corporate Services Agreement*, including: the Chief Executive Officer; Finance; the Company Secretary and Legal; Human Resources; Corporate Affairs; Regulation; Customer Services; Information Technology; and Office Administration; and under the *Metering Services Agreement* a number of metering services, including, new connections, fault replacements, customer initiated replacements, meter maintenance and AMI meter project management and accelerated rollout.

CHED Services entered into an *arm's length* agreement with CitiPower to provide these services from 1 January 2005 and continues to provide these services. In order to facilitate the *Corporate Services Agreement*, CitiPower under the *Resources Agreement* provides staff to CHED Services.

In 2004, CHED Services also established a *Discretionary Risk Management Scheme* (**DRMS**) to provide in-fill insurance cover to CitiPower in respect of amounts below the policy deductibles under the following external insurance policies:

- liability insurance;
- property insurance; and
- motor vehicle insurance.

The DRMS retains funding reserves based on payments made by CitiPower in order to enable CHED Services to meet the cost of claims under the DRMS. Amongst other things, the DRMS details:

- the limits of the cover available to CitiPower; and
- how the contributions that are paid by members, including CitiPower, are determined.

In response to paragraph 6.4(b)(iv), CHED Services does not outsource any of the services it provides to CitiPower to another provider, with the limited exception of the outsourcing of some metering field work to PNS and other services, such as meter reading, special reads and IT projects, to entities not related to either CHED Services or CitiPower.

Silk Telecom/Nextgen Networks

In 2005, ETSA Utilities (**ETSA**) telecommunications division was combined with Powercor Telecom to create a new entity called Silk Telecom which sat outside the CHEDHA Holding group but was owned by Cheung Kong Group; subsequently Silk Telecom was sold to Nextgen Networks in mid 2008. As a result of the sale, Silk Telecom/Nextgen Networks is no longer a related party for the purposes of the generic criteria listed in the RIN definition of *'related party'*.

CitiPower principally uses Silk Telecom/Nextgen Networks as the principal provider for all telecommunication links and services. Under the *Electrical Network Communications Agreement*, Silk Telecom/Nextgen Networks provides electrical services including SCADA and Trunked Mobile Radio Services and, under the *Corporate Communications Agreement*, Silk Telecom/Nextgen Networks provides corporate communications services including; managed wide area network (WAN); WAN links; mobile phones; remote access; PABX, voice and data communications.

In response to paragraph 6.4(b)(iv), Silk Telecom/Nextgen does outsource some services to Powercor Network Services (**PNS**).

Powercor Network Services

In 2008, a separate legal entity, PNS, was separated from CitiPower to provide specialist construction and maintenance services. PNS, which is owned by CHEDHA, provides CitiPower with various services including: customer and connection services; asset replacement maintenance services; asset performance (fault) services; and network development. CitiPower entered into an *arm's length* agreement with PNS to provide these services known as the *Network Services Agreement.*

Services for asset management, network operations and network planning are retained in-house by CitiPower. During 2007, the asset management teams of CitiPower and Powercor Australia were merged under a new agreement (Cost Sharing Agreement)

In response to paragraph 6.4(b)(iv), PNS does outsource a component of the services it provides to CitiPower to other providers in order to deliver the most price efficient outcome for CitiPower's customers.

In order to facilitate the provision of services by PNS to CitiPower under the *Network Services Agreement*, CitiPower provides staff to PNS under the *Resources Agreement* to which they are both parties.

Powercor Australia

Powercor Australia and CitiPower are related parties and each holds a separate electricity distribution licence for a defined geographical electricity distribution area in Victoria. The Distribution Networks are jointly managed and operated by CitiPower and Powercor Australia personnel and systems. Under the *Cost Sharing Agreement*, defined overhead costs incurred by Powercor Australia and CitiPower are apportioned between each respective business.

22.1.3 Service contracts and agreements

Paragraph 6.3 of the RIN requires CitiPower to identify all arrangements or contracts between CitiPower and any of the other entities identified in the response to paragraph 6.1, together with the service or services the subject of each arrangement or contract.

Section 22.1.2 of the RIN Response provides a description of the arrangements or contracts between CitiPower and each of CHED Services, PNS, Silk Telecom/Nextgen Networks and Powercor Australia, and the distribution services provided to CitiPower pursuant to those arrangements or contracts. The arrangements or contracts, and the relevant services provided by CitiPower pursuant to them, are summarised in Table 22.1 below.

Provider	Recipient	Arrangement or Contract	Service	Contract Period
CHED Services	CitiPower	Corporate Services Agreement	Corporate Services	2008-10
PNS	CitiPower	Network Services Agreement	Network Services	2008-10
CHED Services	CitiPower	Metering Services Agreement	Metering and Servicing	2008-13
CitiPower	PNS	Resources Agreement	Resources	2008-10
CitiPower	CHED Services	Resources Agreement	Resources	2008-10
CHED Services	CitiPower	Member of the Scheme since 2005	DRMS	N/A
Powercor Australia	CitiPower	Cost Sharing Agreement	Cost Sharing	2009-16
Silk Telecom	CitiPower	Electrical Network Communications Agreement	Electrical Network Communications	2006-10
Silk Telecom	CitiPower	Corporate Communications Agreement	Corporate Services Communications	2006-10

Table 22.1: Arrangements or contracts between CitiPower and other entities

In response to paragraph 6.5(a) of the RIN, CitiPower has provided a copy of each of the arrangements or contracts listed in the table above as an attachment to this Regulatory Proposal.

22.1.4 Services and costs under each contract and agreement

This sub-section of the Regulatory Proposal addresses the requirements of paragraph 6.5(b), (c), (d) and (e) of the RIN.

Corporate Services Agreement with CHED Services

Pricing of services under the *Corporate Services Agreement* is based on a fixed charge for 2008, with CPI escalations being applied in 2009 and 2010. The agreed 2008 fixed charge was based on forecast efficient costs plus a commercial margin. There are no incentive payments and extra overheads associated with the *Corporate Services Agreement*.

Table 22.2 below provides a breakdown of all of the services provided pursuant to under the Corporate Services Agreement with CHED Services, and a breakdown of the actual costs for each such service for 2008.

[redacted]

Table 22.2: Service and costs provided by CHED Services – Corporate Services

The inclusion of the margin is the only difference between the two cost columns.

There are no incentive payments or overheads payable by CitiPower under the *Corporate Services Agreement*.

The costs reconcile with the 31 December 2008 Regulatory Accounts.

In 2006, CitiPower and Powercor Australia engaged Ernst and Young to establish the appropriate arm's length transfer prices for corporate services provided by CHED Services by applying the processes and methodologies that are accepted by the Australian Taxation Office (**ATO**) with respect to transfer pricing of both domestic and international related party services. Ernst and Young selected a number of comparable companies that provided a similar level of service and/or expertise to CHED Services and recommended the following margins:

- 10.46 per cent for finance services;
- 3.76 per cent for human resources, training and development;
- 15.12 per cent for company secretary and legal, regulation and chief executive officer;[79]
- 10.82 per cent for customer services; and
- 18.93 per cent for IT services.

[79] Ernst and Young, *CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services*, 20 November 2006.

CHED Services adopted the margins as recommended by Ernst and Young in charging CitiPower. There are no other costs included in the contract price under the *Corporate Services Agreement* other than those detailed above.

A recent update by Ernst and Young of the benchmark IT margin indicated that there has been little movement in the benchmark IT margin.[80]

CitiPower has provided the AER with copies of Ernst and Young's reports as attachments to this Regulatory Proposal, in accordance with paragraph 6.5(e) of the RIN.

Metering Services Agreement with CHED Services

Fees under the *Metering Services Agreement* are agreed annually based on contractually defined principles as described in section 22.1.5.

Table 22.3 below provides a breakdown of all of the services provided pursuant to under the *Metering Services Agreement* with CHED Services, and a breakdown of the actual costs for each such service for 2008.

[redacted]

Table 22.3: Service and costs provided by CHED Services – Metering Services

The inclusion of the margin is the only difference between the two cost columns.

There are no incentive payments or overheads payable by CitiPower under the *Metering Services Agreement.*

The costs reconcile with the 31 December 2008 Regulatory Accounts.

In 2006, CitiPower and Powercor Australia engaged Ernst and Young to establish the appropriate arm's length transfer prices for corporate services provided by CHED Services by applying the processes and methodologies that are accepted by the ATO with respect to transfer pricing of both domestic and international related party services. Ernst and Young selected a number of comparable companies that provided a similar level of service and/or expertise to CHED Services and recommended the following margins:

- 11.48 per cent for metering planning and project management services; and

[80] Ernst and Young, *CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services*, 21 May 2009.

- 9.85 per cent for metering customer services.

CHED Services adopted the margins as recommended by Ernst and Young in charging CitiPower. There are no other costs included in the contract price under the *Metering Services Agreement* other than those detailed above.

CitiPower has provided the AER with copies of Ernst and Young's reports as attachments to this Regulatory Proposal, in accordance with paragraph 6.5(e) of the RIN.

Network Services Agreement with PNS

All of the services provided by PNS under the *Network Services Agreement* are detailed in section 22.1.2 of this Regulatory Proposal.

Pricing is based on a mix of fixed price quotes, unit rates and labour rates. PNS expects to earn about a 5.26 per cent margin on its services. The margin is consistent with the commercial margins determined by Ernst and Young.

Table 22.4 below provides a breakdown of all of the services provided pursuant to under the *Network Services Agreement* with PNS, and a breakdown of the actual costs for each such service for 2008.

[redacted]

Table 22.4: Network services and costs provided by PNS

There are corporate overheads and margins payments payable by CitiPower under the *Network Services Agreement*. There were no incentive payments payable by CitiPower in 2008 under the *Network Services Agreement.*

The costs reconcile with the 31 December 2008 Regulatory Accounts, however it is noted there is an error in how they are represented for the purposes of Workpapers Supporting the Regulatory Accounting Statement for 2008. The amount included in the Regulatory Accounts was understated.

In 2006, CitiPower and Powercor Australia engaged Ernst and Young to establish the appropriate arm's length transfer prices for construction and maintenance services provided by PNS by applying the processes and methodologies that are accepted by the ATO with respect to the pricing of both domestic and international related party services. Ernst and Young selected a number of comparable companies that provided a similar level of service and/or expertise to PNS and recommended that a mark-up of 5.26 per cent for Construction and Maintenance Services were commercially realistic mark-ups.[81]

PNS adopted the margins as recommended by Ernst and Young in charging CitiPower. There are no other costs included in the contract price under the *Network Services Agreement* other than those detailed above.

CitiPower has provided the AER with copies of Ernst and Young's reports as attachments to this Regulatory Proposal, in accordance with paragraph 6.5(e) of the RIN.

Resources Agreements with PNS and CHED Services

All of the services provided by CitiPower under the Resources Agreements with each of PNS and CHED Services are detailed in section 22.1.2 of this Regulatory Proposal.

PNS and CHED Services, under their respective *Resources Agreements*, pay CitiPower; wages and salaries (including bonuses, allowances, leave payments, fringe benefits, fringe benefit tax, payroll tax, superannuation payments and work cover payments); operating expenses that are incidental to the provision of the services by CitiPower (including phone calls, stationary, etc); and motor vehicle expenses relating to provision of the services to CitiPower.

There are no incentive payments, overheads, management fees or margins payable by PNS or CHED Services under the *Resources Agreements*.

As the services provided pursuant to the Resources Agreements are provided by CitiPower at cost, CitiPower has no methodologies, consultants' reports or assumptions used to determine components of the costs included in the contract price to provide to the AER pursuant to paragraph 6.5(e) of the RIN.

DRMS charges payable to CHED Services

The insurance services provided to CitiPower by CHED Services under the DRMS are detailed in section 22.1.2 of this Regulatory Proposal.

CHED Services charges CitiPower a fee for the insurance services in accordance with external actuarial assessment and advice. The fee is comprised of the actual cost of the service and a margin of 3.2 per cent. For the purposes of paragraph 6.5(e) of the RIN, the actuarial assessment from the Aon *Powercor Australia Self Insurance Risk Quantification Report, June 2007*, is provided as an attachment to this Regulatory

[81] Ernst and Young, *CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Construction and Maintenance Services*, 30 November 2006.

Proposal. There are no other relevant methodologies, consultants' reports or assumptions that were used to determine components of the charges under the DRMS.

Table 22.5 sets out the infill insurance charge for 2008.

[redacted]

Table 22.5: Infill insurance premium

The costs reconcile with the 31 December 2008 Regulatory Accounts.

There are no overheads, incentive payments or management fees associated with the DRMS.

Cost Sharing Agreement with Powercor Australia

The benefits provided to Powercor Australia by the *Cost Sharing Agreement* are detailed in section 22.1.2 of this Regulatory Proposal.

The *Cost Sharing Agreement* entails an annual payment being made between CitiPower and Powercor Australia. The payment is based on the pooling of defined overhead costs and the reallocation of those costs to each distributor based on a defined formula. The difference between the reallocation amount and the actual cost incurred by each distributor is the amount that is paid by one distributor to the other.

There are no overheads, incentive payments, management fees or margins associated with the *Cost Sharing Agreement*.

As the payment made pursuant to the *Cost Sharing Agreement* is referable to actual costs incurred, CitiPower has no methodologies, consultants' reports or assumptions used to determine components of the costs included in the contract price to provide to the AER pursuant to paragraph 6.5(e) of the RIN.

Electrical Network Services Communications Agreement and Corporate Services Communications Agreement with Silk Telecom

Prices for the *Electrical Network Services Communications Agreement* and the *Corporate Services Communications Agreement* have been based on a cost plus basis, which are the actual costs that Silk Telecom/Nextgen Networks will incur directly in providing the services plus a margin which varies in amount depending of the level of '*add-on*' services offered by Silk Telecom/Nextgen. For example, where Silk Telecom/Nextgen provides minimal '*add-on*' services, the margin is generally 10 per cent.

Table 22.6 below provides a breakdown of all of the services provided pursuant to under the *Electrical Network Services Communications Agreement* and the *Corporate Services Communications Agreement*, and a breakdown of the actual costs for each such service for 2008.

[redacted]

Table 22.6: Electrical Network Services Communications Agreement and Corporate Communications Services Agreement

The inclusion of the implied margin is the only difference between the two cost columns. The costs reconcile with the 31 December 2008 Regulatory Accounts.

There are no overheads, incentive payments or management fees associated with the *Electrical Network Services Communications Agreement* and the *Corporate Services Communications Agreement.*

CitiPower found that there was no direct market evidence or third party benchmarks that were sufficiently comparable taking into account the nature and quantity of the services provided by Silk Telecom. The agreements do provide, however, that, if a party forms the view that any component of the standard service charge no longer reflects current market prices, it may give notice to the other party to engage in good faith discussions to amend the agreement. In addition, both of these Agreements with Silk Telecom expire in 2010, at which time CitiPower is committed to a competitive tendering process for the future procurement of the services currently provided by Silk Telecom.

CitiPower has no consultants' reports used to determine components of the costs included in the contract price to provide the AER pursuant to paragraph 6.5(e) of the RIN.

22.1.5 Governance arrangements for the engagement of related parties

This sub-section addresses the requirements of paragraph 6.4(a)(i) and (ii) of the RIN and 6.4(b)(ii), and (iii).

Network Services Agreement with PNS, Corporate Services Agreement and Metering Services Agreement with CHED Services, Resources Agreements with PNS and CHED Services and Cost Sharing Agreement with Powercor Australia

CitiPower did not procure the services provided by CHED Services, PNS and Powercor Australia under the *Network Services Agreement*, *Corporate Services Agreement*, *Metering Services Agreement*, *Resources Agreements* and *Cost Sharing Agreement* on a competitive basis or conduct a tendering process. Rather, CitiPower negotiated directly with these entities for the provision of the respective services on a cost plus benchmark margin basis because it considered that this would deliver the most efficient price-service outcome for CitiPower, and therefore its customers. Accordingly, CitiPower has no tendering documentation to provide to the AER in respect of these Agreements in accordance with paragraph 6.4(a)(ii) of the RIN.

CitiPower procured the outsourced services on a stand-alone basis and the engagement of each of CHED Services, PNS and Powercor Australia is not part of a broader operational agreement.

In 2006, CitiPower's Board established strict governance arrangements for the engagement of related parties.

The principles established by the Board include:

- related party transactions are supported by contracts;
- contracts are commercial and arm's length, this includes: ensuring that prices are based on market prices or comparable prices to unrelated parties and costs plus a commercial margin; a mechanism for passing through efficiencies; a clear description of the services provided; specified service levels and/ or Key Performance Indicators (**KPIs**) that are required by service recipients; and a reduction in fees for excessive, or enduring, poor performance;
- independent verification of the arm's length nature of contracts;
- transactions comply with relevant laws; and
- transactions comply with undertakings to bond holders, banks, insurers and rating agencies.

Prior to executing these agreements, CitiPower engaged KPMG to assess whether the *Network Services Agreement, Corporate Services Agreement, Metering Services*

Agreement, Resources Agreements and the *Cost Sharing Agreement* comply with the principles established by the Board. CitiPower has provided the AER with a copy of each of the KPMG reports that confirms this compliance, as an attachment to this Regulatory Proposal.

DRMS

CitiPower's risk management philosophy with respect to insurance is to retain those exposures it can manage economically and to obtain commercial insurance for those exposures which have the potential to cause financial distress.

As a result of this risk management philosophy, CitiPower considered the best and most efficient way to manage its risks was to obtain insurance cover from CHED Services.

As a consequence, CitiPower did not procure the services provided by CHED Services under the DRMS on a competitive basis or conduct a tendering process and, accordingly, CitiPower does not have any tendering documentation to provide to the AER in respect of the services procured under the DRMS in accordance with paragraph 6.4(a)(ii) of the RIN.

CitiPower procured the outsourced services on a stand-alone basis and the engagement is not part of a broader operational agreement.

Cost Sharing Agreement with Powercor Australia

The cost sharing that occurs between CitiPower and Powercor Australia pursuant to the Cost Sharing Agreement is only available to CitiPower in respect of Powercor Australia. Accordingly, CitiPower did not procure the benefits flowing to it under the Cost Sharing Agreement on a competitive basis or through competitive tendering. Accordingly, CitiPower has no tendering documentation to provide to the AER in respect of this Agreement in accordance with paragraph 6.4(a)(ii) of the RIN.

CitiPower procured the benefits under the Cost Sharing Agreement on a stand-alone basis and the engagement is not part of a broader operational agreement.

Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom

CitiPower did not procure the services from Silk Telecom/Nextgen Networks on a competitive basis or conduct a tendering process. Rather, CitiPower negotiated directly with Silk Telecom/Nextgen Networks for the provision of telecommunication and related services because it considered that this would deliver the most efficient price-service outcome for CitiPower, and therefore its customers. Accordingly, CitiPower has no tendering documentation to provide to the AER in respect of these Agreements in accordance with paragraph 6.4(a)(ii) of the RIN.

CitiPower procured the outsourced services on a stand-alone basis and the engagement is not part of a broader operational agreement.

22.1.6 Benefits of restructure relative to in-house service provision

Paragraph 6.4(b)(i) of the RIN requires CitiPower to explain why the service that is the subject of an arrangement or contract identified in response to paragraph 6.3 of the RIN has been outsourced instead of being undertaken by CitiPower itself.

The primary purpose of restructuring CitiPower's service provision model over the current regulatory control period has been to strengthen the focus on long term asset ownership and performance. The service provision model has allowed:

- a sharper focus on the core asset management and ownership function;
- greater potential for the cost-efficient provision of network, telecommunication and back office services;
- greater accountability for service cost and quality;
- greater potential for improving service levels and performance; and
- greater focus on growth of the construction and field services and corporate services businesses by providing services to multiple clients.

CitiPower has engaged KPMG to quantify the efficiencies that are captured by CitiPower's service provision model, specifically in relation to network and corporate services, relative to it providing these nominated services in-house. CitiPower has provided the AER with a copy of KPMG's report as an attachment to this Regulatory Proposal.

Efficient in-house cost forecasts were calculated by KPMG using publicly available sources of benchmarking information. KPMG found that CHED Services and PNS were in a better position to achieve lower costs and improved service performance than CitiPower could on a stand-alone basis. These service providers are able to access economies of scale in both the delivery, and procurement, of services that they would not otherwise have been able to capture had they remained part of CitiPower.

KPMG also noted that extending the market for PNS' services beyond CitiPower and Powercor Australia may lead to an increase in purchasing influence, for example in sub-contractor services. However, KPMG did not seek to quantify the potential efficiencies that may have been achieved through purchasing influence.

KPMG further concluded that the efficiency of these arrangements is reflected in the outturn performance of both CitiPower and Powercor Australia over the 2006-10 regulatory control period. In particular, KPMG found that, if CitiPower had delivered its nominated services for the year ended 31 December 2008 on a standalone basis, its efficient cost of service delivery would have been $19.049 million (45 per cent)($2008) more than the costs it actually incurred for these services (excluding related party margins). In particular, in house:

- corporate and customer services would have cost $11.968 million ($2008) more than it actually incurred;

- asset management services would have cost $3.794 million ($2008) more than it actually incurred; and
- network services would have costs $3.287 million ($2008) more than it actually incurred.

DRMS

In response to paragraph 6.4(b)(i) of the RIN, CitiPower considered outsourcing its insurance cover to CHED Services was to the best and most efficient way to manage its risks. As stated, CitiPower's risk management philosophy with respect to insurance is to retain those exposures it can manage economically and to obtain commercial insurance for those exposures which have the potential to cause financial distress.

Electrical Network Services Communications Agreement and Corporate Services Communications Agreement with Silk Telecom

In response to paragraph 6.4(b)(i) of the RIN, CitiPower considered outsourcing its telecommunication services would allow for:

- greater potential for the cost-efficient provision of telecommunication services;
- greater accountability for service cost and quality; and
- greater potential for improving service levels and performance.

22.1.7 Regulatory treatment of outsourcing arrangements

The most comprehensive regulatory framework that has been used in Australia to date for examining outsourcing agreements is that applied by the ESCV for its 2008-2012 Gas Access Arrangement Review (**GAAR**) for the gas distribution businesses, MultiNet; Envestra and SP AusNet.[82]

The three gas distribution businesses each outsource significant aspects of their operations to third-party providers – in two instances to *'related'* parties. In considering whether these arrangements met the criteria specified in sections 8.16(a)(i) and 8.37 of the Gas Code (**the Code**), the ESCV adopted a *case-by-case* approach, with a view to determining whether the following two thresholds are met, being that:

- the reported costs represented the actual costs incurred in providing the services and not costs or payments for other matters; and
- the gas distribution business has acted prudently in contracting on the basis of paying for an efficient level of costs, so as to achieve the lowest sustainable cost of providing the services (consistent with the Code's requirements).

The ESCV noted that, where it could be satisfied that payments made under an outsourcing contract were lower than the costs that would likely be incurred by a

[82] Essential Services Commission, *2008-2012 Gas Access Arrangement Review*, 7 March 2008.

distribution business in undertaking those activities itself, then the payments made under those contracts are likely to be consistent with the Code.

Under the ESCV's framework, if an outsourcing contract meets the *'thresholds'*, the full contract price, including any explicit or implicit margin, will be adopted as the cost benchmark. This could result in a contractor:

- receiving an explicit or implicit margin above its directly incurred costs, for example to reflect economies of scale, scope and other efficiencies not available to the regulated business; and
- retaining, for a period, any efficiency gains that it achieves without being forced to pass them through to the regulated business and ultimately consumers at a rate determined by the regulator.

CitiPower considers that the AER should apply the ESCV's framework in assessing CitiPower's expenditure for the purposes of clauses 6.5.6(e)(9) and 6.5.7(e)(9) of the Rules. These provisions in respect of operating expenditure and capital expenditure respectively are substantively similar and require the AER, in deciding whether CitiPower's expenditure satisfies the operating and capital expenditure criteria, to have regard to:

> *'the extent the forecast of required operating/capital expenditure of the Distribution Network Service Provider is referrable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms.'*

CitiPower maintains that its Network Services Agreement with PNS and Corporate Services Agreement with CHED Services have been developed on an arm's length basis and reflect arm's length terms, in accordance with the principles laid down by CitiPower's Board.

23. ALTERNATIVE CONTROL SERVICES

This Chapter provides information in relation to CitiPower's Alternative Control Mechanism and addresses the requirements of the Rules and paragraph 15 of the AER's RIN. The Alternate Control Services in this Regulatory Proposal are the Public Lighting Services described in section 23.1, Fee Based Services described in section 23.2 and Quoted Services described in section 23.3.

CitiPower notes at the outset many alternate control service charges have not been revised for a considerable period of time. This has resulted in CitiPower incurring losses on a number of these services. The extent of these losses is outlined in 2008 Regulatory Accounts. The philosophy adopted throughout this Chapter has been to ensure the Business fully recovers its costs on those services for which it is presently reporting losses.

23.1 Public lighting services

23.1.1 Nature of services

The only Public Lighting Service that is classified as an Alternative Control Service relates to the operation, maintenance, repair, replacement (OM&R) of CitiPower's public lighting assets. CitiPower proposes that its other Public Lighting Services – new public lighting and alteration and relocation of DNSP public lighting assets – be classified as Negotiated Distribution Services, consistent with the AER's proposed classification in its Framework and Approach Paper.

23.1.2 Current regulatory control period

Charging methodology

The current charges for CitiPower's Public Lighting Services were determined in the ESCV's August 2004 *Review of Public Lighting Excluded Service Charges – Final Decision* (**2004 Public Lighting Final Decision**) and the AER's February 2009 *Energy Efficient Public Lighting Charges – Victoria Final Decision* (**2009 Energy Efficient Public Lighting Final Decision**).

The 2004 Public Lighting Final Decision determined a set of charges to apply from October 2004 and a basis for adjusting these charges from year to year for a return on and of assets. The 2009 Energy Efficient Public Lighting Final Decision relates to the operation, maintenance and replacement charges for T5 public lighting and the MV80 written down value and avoided costs for the period to 31 December 2010.

Unit costs

Tables 2.1 to 2.7 in the 2004 Public Lighting Final Decision detail the unit costs that were used to develop the public lighting Excluded Service charges for the current regulatory control period.

Customers or jobs

The number of public lights that attract a public lighting charge for each year of the current regulatory control period is provided in Table 23.1 with actual data used for 2006-08 and estimates used for 2009-10.

	Lights				
	Actual			Forecast	
Name of service	2006	2007	2008	2009	2010
Mercury vapour 125W	2,539	2,516	2,453	2,400	2,337
Mercury vapour 250W	1,342	1,295	1,267	1,165	1,137
Mercury vapour 400W	789	701	622	527	452
Mercury vapour 50W	638	626	616	608	596
Mercury vapour 700W	8	8	8	4	4
Mercury vapour 80W	23,430	23,478	23,433	23,439	17,579
Fluorescent 20W	33	37	37	37	37
Sodium high pressure 1000W	27	27	19	16	16
Sodium high pressure 100W	462	460	453	452	445
Sodium high pressure 150W	13,861	13,905	13,983	12,210	12,294
Sodium high pressure 220W	2,667	2,467	2,387	2,363	2,363
Sodium high pressure 250W	4,775	5,089	5,217	4,512	4,622
Sodium high pressure 360W	369	307	297	292	292
Sodium high pressure 400W	498	498	502	395	138
Sodium high pressure 70W	531	519	512	514	508
Metal halide 1000W	13	12	11	10	10
Metal halide 100W	240	216	231	242	259
Metal halide 150W	131	248	372	446	446
Metal halide 250W	203	211	251	355	192
Metal halide 400W	1,112	1,164	1,174	1,187	1,199
Metal halide 70W	752	846	904	977	977
Compact fluorescent T5 (2 X 14W)	-	-	-	-	5,808
Replacement luminaire	-	-	-	-	-

Table 23.1: CitiPower's public lights that attract a public lighting charge

Prices

CitiPower provides prices for its Public Lighting Services for each year of the current regulatory control period is provided in Table 23.2.

	$'s (nominal terms)				
	Actual			Forecast	
Name of service	2006	2007	2008	2009	2010
Mercury vapour 125W	42.14	42.14	73.59	64.39	68.46
Mercury vapour 250W	49.97	49.97	68.17	62.28	67.91
Mercury vapour 400W	50.50	50.50	69.05	63.02	68.72
Mercury vapour 50W	36.64	36.64	67.49	57.87	61.53
Mercury vapour 700W	74.62	74.62	101.16	92.68	101.06
Mercury vapour 80W	29.30	29.30	43.68	40.75	43.33
Fluorescent 20W	37.17	37.16	110.19	81.09	86.23
Sodium high pressure 1000W	117.81	117.81	160.66	146.80	160.08
Sodium high pressure 100W	60.17	60.17	81.35	74.45	81.23
Sodium high pressure 150W	59.96	59.96	78.68	72.99	79.64
Sodium high pressure 220W	60.83	60.83	80.00	74.31	81.01
Sodium high pressure 250W	60.69	60.69	79.83	74.14	80.85
Sodium high pressure 360W	61.01	61.01	82.41	75.62	82.47
Sodium high pressure 400W	65.22	65.22	89.51	81.56	88.94
Sodium high pressure 70W	56.51	56.51	98.77	86.39	91.86
Metal halide 1000W	106.84	106.84	144.87	132.71	144.72
Metal halide 100W	93.50	93.50	124.25	114.59	125.03
Metal halide 150W	93.81	93.81	125.35	115.32	125.83
Metal halide 250W	71.53	71.53	97.22	88.97	97.02
Metal halide 400W	71.53	71.53	97.22	88.97	97.02
Metal halide 70W	79.11	79.11	87.02	133.25	141.69
Compact fluorescent T5 (2 X 14W)	-	-	-	30.07	30.35
Replacement luminaire*	-	-	-	73.34	79.59
* Avoided cost and written down value, this is a once off payment to settle the residual value where a compact fluorescent is used to replace an existing light. It does not include the program cost to rollout energy efficient lights, this is a negotiated fee.					

Table 23.2: CitiPower's prices for Public Lighting Services

Revenue

Information about CitiPower's revenues from Public Lighting Services for each year of the current regulatory control period is provided in Table 23.3 with actual data used for 2006-08 and estimates used for 2009-10.

	$000's (real 2010)				
	Actual			Forecast	
Name of service	2006	2007	2008	2009	2010
Mercury vapour 125W	120	114	175	156	160
Mercury vapour 250W	70	65	78	73	77
Mercury vapour 400W	42	33	38	34	31
Mercury vapour 50W	26	25	40	36	37
Mercury vapour 700W	-	-	-	-	-
Mercury vapour 80W	769	742	985	967	762
Fluorescent 20W	1	1	4	3	3
Sodium high pressure 1000W	4	3	3	2	3
Sodium high pressure 100W	31	30	36	34	36
Sodium high pressure 150W	809	785	924	902	979
Sodium high pressure 220W	184	160	185	178	191
Sodium high pressure 250W	274	294	349	339	374
Sodium high pressure 360W	23	18	21	22	24
Sodium high pressure 400W	28	27	33	33	12
Sodium high pressure 70W	34	32	49	45	47
Metal halide 1000W	1	1	1	1	1
Metal halide 100W	25	22	28	28	32
Metal halide 150W	19	25	43	52	56
Metal halide 250W	16	16	23	32	19
Metal halide 400W	89	90	110	107	116
Metal halide 70W	66	74	139	132	136
Compact fluorescent T5 (2 X 14W)	-	-	-	-	176
Replacement luminaire*	-	-	-	-	-
* Avoided cost and written down value, this is a once off payment to settle the residual value where a compact fluorescent is used to replace an existing light. It does not include the program cost to rollout energy efficient lights, this is a negotiated fee.					

Table 23.3: CitiPower's revenues for Public Lighting Services

Evidence costs not compensated elsewhere

CitiPower's Regulatory Accounts include a template for *'Excluded Services and Other Activities'*, which distinguishes between public lighting and other Excluded Services.

The 2008 Regulatory Accounts have been prepared in accordance with the ESCV's *Guideline No. 3 Regulatory Accounting Information Requirements Final Decision*

December 2006. The principles for the attribution and allocation of costs are reflected into CitiPower's accounting system.

CitiPower's chart of accounts classifies all costs and revenues by general ledger account numbers, which map to reporting categories on the balance sheet and profit and loss statement. Each cost or revenue transaction is also assigned to a profit centre. Each cost item is also assigned a function code and, in some cases, an activity type. CitiPower's Regulatory Accounts are externally audited each year.

On this basis, it is clear that the existing costs of CitiPower's Excluded Services (including Public Lighting Services) are not compensated elsewhere.

23.1.3 Next regulatory control period

Charging methodology

CitiPower's methodology for developing its OM&R charges for Public Lighting Services in the next regulatory control period involves applying a limited building block approach, as reflected in the AER's public lighting model.

CitiPower has provided a completed version of AER's public lighting model, as an attachment to this Regulatory Proposal.

Application of control mechanism

Section 3.7.8 of the AER's Framework and Approach Paper provides that a price cap form of control will apply to Public Lighting Services in the next regulatory control period. It states that *'the price cap for the operation, repair, replacement and maintenance of public lighting assets will be established based on a limited building block approach, where DNSPs will be required to forecast their opex and capex for public lighting services over the regulatory control period'*.

As noted above, CitiPower has applied the limited building block approach as reflected in the AER's public lighting model making the following adjustments to the mode inputs:

- *escalation factors* - CitiPower has adopted labour and material price escalation at rates consistent with the Standard Control Services, as set out in sections 7.2.1 and 7.2.2 of this Regulatory Proposal. Additionally a nominal CPI price escalation has been applied using the same assumptions as those used in the broader submission;
- *initial labour rates* – CitiPower has used an initial labour rate ($2010) that is consistent with that applied to Standard Control Services;
- *real pre-tax WACC* - CitiPower has used a WACC rate that is consistent with that used for Standard Control Services;
- *hours per day* - consistent with current award conditions, CitiPower has amended the number of hours per day from $8^1/_3$ hours to 8 hours. Consequently, the

amount of work completed per day has been scaled back by 4 per cent. This includes:

- o number of bulk lamp changes in 1 day;
- o number of repairs in 1 day;
- o pole inspection rate (per day);
- o number of poles & brackets replaced per day; and
- o number of brackets replaced per day.

- *proportion of luminaires that fail between bulk changes* - consistent with earlier submissions, the T5-14 light type has had the proportion of luminaires that fail between bulk change amended to 18.5 per cent;

- *T5 - unit cost – luminaire* - the default price per luminaire is $193 ($2010). This price was obtained from the Municipal Association of Victoria (**MAV**) based on a mass rollout across the whole state. Operation, repair, replacement and maintenance services however are more sporadic and, therefore CitiPower will not be able to negotiate such a bulk supply discount. As a substitute CitiPower has used a previous quote of $215 ($2010) as a cost input;

- *traffic control costs* - CitiPower has determined that the traffic control costs are $15.48 (in $2010) per light for bulk replacement activities. This cost is likely to be even higher for fault activities;

  In the *Review of Public Lighting Excluded Service Charges, Final Decision*, August 2004, the ESCV granted an allowance for half of one full time for traffic management purposes (refer to table 2.3 of the ESCV's final Decision). In moving to a per light unit rate for traffic management, CitiPower has scaled back the allowance to ensure there is no double counting of this cost input;

- *dedicated street lighting poles – cost of pole and bracket* – CitiPower has determined that the unit costs of these activities are $3,125 ($2010);

- *patrol costs* - costs have been amended to $25.00 per hour ($2010) to reflect the current contract prices; and

- *existing light prices* - CitiPower has provided with this Regulatory Proposal, the public lighting OM&R rates submitted for approval to the AER on 17 November 2009. At the time of submitting this Regulatory Proposal, these rates have not been approved by the AER.

Unit costs

Information about CitiPower's proposed unit cost inputs that it has used to calculate its proposed charges for Public Lighting Services in the current regulatory control period are detailed in the completed public lighting model.

Indicative prices

The indicative prices for CitiPower's Public Lighting Services for each year of the next regulatory control period are detailed in the completed public lighting model and set out below in Table 23.4.

	$'s (nominal)				
	Forecast				
Name of service	2011	2012	2013	2014	2015
Mercury vapour 125W	135.86	136.26	50.36	51.65	52.99
Mercury vapour 250W	108.30	109.55	108.85	112.00	116.35
Mercury vapour 400W	109.59	110.85	110.15	113.33	117.74
Mercury vapour 50W	122.10	122.46	45.26	46.42	47.62
Mercury vapour 700W	161.16	163.02	161.98	166.66	173.14
Mercury vapour 80W	85.99	86.24	31.87	32.69	33.54
Fluorescent 20W	171.11	171.62	63.43	65.05	66.74
Sodium high pressure 1000W	255.28	258.22	256.57	263.99	274.26
Sodium high pressure 100W	129.92	131.55	130.63	134.47	139.73
Sodium high pressure 150W	127.37	128.97	128.07	131.84	136.99
Sodium high pressure 220W	129.19	130.68	129.84	133.60	138.79
Sodium high pressure 250W	128.93	130.41	129.58	133.33	138.51
Sodium high pressure 360W	131.51	133.02	132.17	135.99	141.29
Sodium high pressure 400W	141.82	143.46	142.54	146.66	152.37
Sodium high pressure 70W	182.29	182.83	67.57	69.30	71.10
Metal halide 1000W	230.79	233.44	231.95	238.66	247.94
Metal halide 100W	199.97	202.48	201.07	206.98	215.08
Metal halide 150W	201.24	203.77	202.35	208.30	216.45
Metal halide 250W	154.72	156.50	155.50	159.99	166.22
Metal halide 400W	154.72	156.50	155.50	159.99	166.22
Metal halide 70W	281.17	282.00	104.22	106.89	109.67
Compact fluorescent T5 (2 X 14W)	61.25	64.35	60.30	63.07	65.91
Replacement luminaire*	118.35	70.26	53.91	(4.44)	(8.00)
* Avoided cost and written down value, this is a once off payment to settle the residual value where a compact fluorescent is used to replace an existing light. It does not include the program cost to rollout energy efficient lights, this is a negotiated fee.					

Table 23.4: CitiPower's indicative prices for Public Lighting Services

Evidence costs not compensated elsewhere

CitiPower has applied its Cost Allocation Method to directly attribute, and allocate, costs between Standard Control Services, Alternative Control Services and Negotiated

Distribution Services in the next regulatory control period. CitiPower will reflect the principles for the attribution and allocation of costs into its accounting system in the same manner as currently occurs.

The costs for Alterative Control Services will then be recovered through Public Lighting Services, Fee Based Services or Quoted Services.

Justification of different charges between customers

CitiPower proposes continuing its current practice of differentiating charges to customers for its Public Lighting Services based on:

- the type of public lighting – different charges apply to fluorescent, mercury vapour, sodium low pressure, incandescent and metal halide lights; and
- the wattage of the lighting – more than one wattage level applies to each of the five lighting types.

These charges reflect the different costs of providing each of these public lighting types and wattages.

23.2 Fee Based Services

23.2.1 Nature of services

Paragraph 15.2(a)(i) of the RIN requires CitiPower to describe its Fee Based Services. This information is provided in Table 23.5.

Fee Based Service	Description
De-energisation of existing premises	This charge applies where a customer or a customer's retailer requests that a supply point with fuses less than 100 Amps be de-energised and a field visit is required. This charge includes De-energisation after non-payment. This charge applies to remote de-energisation for AMI meters. This service is only provided during Business Hours.
Re-energisation of existing premises	This charge applies where a customer or a customer's retailer requests that a supply point with fuses less than 100 Amps be re-energised and a field visit is required. A supply point for an existing customer may be re-energised where: • the customer has previously requested that a supply be de-energised temporarily and now wishes the supply to be restored; or • the customer has been disconnected for non-payment but does not require immediate reconnection and has agreed to wait for a standard reconnection appointment. • The customer has been disconnected for non-payment and requires a same day reconnection. This charge includes customer transfers.

Fee Based Service	Description
	This charge applies to remote re-energisation for AMI meters. Different charges apply depending on whether the service is provided: • The same day the request was made; • The next day after the request was made during business hours; and • The next day after the request was made after business hours.
Wasted attendance – not DNSP fault	This charge applies to all service truck visits requested by a customer or contractor and attended by CitiPower where the truck arrives to find the customer or contractor is not ready for the scheduled work or the truck attendance is not required. 24 hours notice is required to cancel a truck appointment otherwise the wasted truck visit charge will apply. This charge is levied in addition to a charge for a service truck visit, which is required to complete the required work. Different charges apply depending on whether the service is provided during, or after, business hours.
Service truck visits	This charge applies to service truck visits requested by customers and contractors. Different charges apply depending on whether the service is provided during, or after, business hours.
Supply abolishment	This charge applies where a retailer or customer requests that CitiPower abolish supply at a premises. This involves decommissioning of a National Metering Identifier and all associated metering, where CitiPower is acting as metering provider. Different charges apply depending on whether the service is provided during, or after, business hours. The charges imposed for this service are the same as for a service truck visit.
Fault response – not DNSP fault	This charge applies where CitiPower has made a service truck visit at the request of a customer or contractor where the fault is found to be caused by the customer, rather than CitiPower. For example, the customer would be at fault: • where they are not receiving supply and they have not checked that the cause is that the main switch or safety switch is not in the 'on' position; and • where there are quality of supply issues that have been caused downstream of CitiPower's distribution system. This charge applies to service truck visits requested by customers and contractors. Different charges apply depending on whether the service is provided during, or after, business hours.
Meter investigation	This charge applies where a retailer requests CitiPower to investigate the metering at a given connection point. This request may be initiated either by the retailer itself or a customer. Different charges apply depending if the service is provided during, or after, business hours.
Meter investigation and meter	This charge applies where a retailer requests CitiPower to test the accuracy of

Fee Based Service	Description
testing	the metering at a given supply point. Different charges apply depending on the type of meter being tested, if it is the primary or secondary meter and whether the service is provided during, or after, business hours.
Special reading	This charge applies where a retailer requests CitiPower to perform a special meter reading and a field visit is required. This is non-scheduled meter reading that is not associated with a re-energisation or a de-energisation of an existing premises. This service is only provided during Business Hours.
PV installation	This charge applies where a customer requests CitiPower to connect an embedded generator to our network. Different charges apply depending on the type of supply connected to the embedded generator and whether the service is provided during, or after, business hours.

Table 23.5: CitiPower's Fee Based Services

CitiPower notes that, as discussed in Chapter 3 of this Regulatory Proposal, it is proposing to amend the list of Fee Based Services proposed by the AER in its Framework and Approach Paper as detailed in Table 23.6.

Service	AER's indicative classification in Framework and Approach paper	CitiPower's proposed classification
Connection and augmentation works for new connections	Negotiated Distribution Services	Standard Control Service
Auditing of design and construction	Alternative Control Service – Quoted Service	Standard Control Service
Specification and design enquiry	Alternative Control Service – Quoted Service	Standard Control Service
Temporary supply services	Alternative Control Service – Fee Based Service	Standard Control Service
Location of underground cables	Alternative Control Service – Fee Based Service	Standard Control Service
Covering of low voltage mains for safety reasons	Alternative Control Service – Fee Based Service	Standard Control Service
Elective underground service where an existing overhead service exists	Alternative Control Service – Fee Based Service	Standard Control Service
Fault tolerance service	Not classified	Standard Control Service
Reserve feeder	Not classified	Negotiated Distribution Services
Meter investigation	Not classified	Alternative Control Service – Fee Based Service
Special reading	Not classified	Alternative Control Service – Fee Based Service
PV installation	Not classified	Alternative Control Service – Fee Based Service

Re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh	Alternative Control Service – Fee Based Service	Not regulated
Energisation of new connections	Alternative Control Service – Connection Service	Alternative Control Service – Fee Based Service
Damage to overhead service cables caused by high load vehicles	Alternative Control Service – Fee Based Service	Alternative Control Service – Quoted Service
High load escorts – lifting overhead lines	Alternative Control Service – Fee Based Service	Alternative Control Service – Quoted Service

Table 23.6: Differences between AER's indicative, and CitiPower's proposed, services classification

23.2.2 Current regulatory control period

Charging methodology

Paragraph 15.2(a)(vi) of the RIN requires CitiPower to provide information about the methodologies and assumptions used to derive its charges for Fee Based Services in the current regulatory control period. CitiPower notes that these services are classified by the ESCV as Excluded Services under the 2006-10 EDPR.

The current charges for CitiPower's Fee Based Services have their origin in the *'SECV Standard Service Prices'* that originally took effect on 1 November 1993.

CitiPower's current charges for its Fee Based Services are those detailed in its current *Excluded Services: Prices, Definitions and Policy*, which reflects the outcomes of the ESCV's 2006-10 EDPR. This policy document sets out the methodologies and assumptions used to derive existing charges for Fee Based Services and has been provided to the AER as Attachment C0097 to this Regulatory Proposal.

Unit costs

Paragraphs 15.2(a)(ix) and 15.2(a)(x) of the RIN require CitiPower to provide information about the unit cost inputs used to calculate existing charges if available.

CitiPower has not used unit costs as a basis for preparing its charges for Fee Based Services. Rather, its current charges are based on the *'SECV Standard Service Prices'* and certain adjustments that are discussed above.

Customers or jobs

Paragraph 15.1(a)(ii) of the RIN requires CitiPower to provide information about the number of customers or jobs for its Fee Based Services for each year of the current regulatory control period. This information is provided in Table 23.7 with actual data used for 2006-08 and estimates used for 2009-10.

	Customer numbers				
	Actual			Forecast	
Name of service	2006	2007	2008	2009	2010
Reconnection fee BH	2,262	2,449	3,314	4,020	4,876
Reconnection fee AH	78	53	380	461	559
Reconnection fee (same day) BH	-	-	-	-	-
Special reader visit fee BH	31,157	33,738	45,648	55,369	67,160
Special reader visit fee AH	22	15	107	129	157
Time switch adjust	1	0	0	0	0
Customer transfer BH	45,502	49,272	66,666	80,863	98,083
Customer transfer AH	1,873	1,285	9,156	11,106	13,472
Disconnection (incl de-energisation after non-payment) BH	309	836	846	1,026	1,245
Disconnection (incl de-energisation after non-payment) AH	49	195	170	206	250
Service truck visit BH	2,892	2,531	3,736	4,247	4,828
Service truck visit AH	239	112	170	143	121
Wasted truck visit BH	-	-	-	-	-
Wasted truck visit AH	-	-	-	-	-
Switching service	2	0	0	0	-
Service truck visit - each add 15 min BH	3,426	1,250	1,181	693	407
Service truck visit - each add 15 min AH	318	118	155	91	53
Meter test single phase	499	372	269	198	145
Meter test single phase AH	-	-	-	-	-
Meter test single phase additional meter	11	6	0	0	0
Meter test multi phase	35	75	45	51	58
Meter test multi phase AH	-	-	-	-	-
Meter test multi phase additional meter	2	1	0	0	0
Meter test CT BH	-	-	-	-	-
Meter test CT AH	-	-	-	-	-
Meter investigation BH	-	-	-	-	-
Meter investigation AH	-	-	-	-	-
Metering services for unmetered supplies	44,307	51,844	51,976	56,295	60,972
Solar PV connection - BH	NA	NA	NA	720	1,500
Solar PV connection - AH	NA	NA	NA	NA	NA

Table 23.7: CitiPower's customers or jobs for Fee Based Services

Prices

Paragraph 15.2(a)(iv) of the RIN requires CitiPower to provide information about the prices for its Fee Based Services for each year of the current regulatory control period. This information is provided in Table 23.8, although it is noted that the same prices will apply for each of the five years.

	$'s (nominal terms)				
	Actual			Forecast	
Name of service	2006	2007	2008	2009	2010
Reconnection fee BH	23.82	23.82	23.82	23.82	23.82
Reconnection fee AH	155.77	155.77	155.77	155.77	155.77
Reconnection fee (same day) BH	-	-	-	-	-
Special reader visit fee BH	23.82	23.82	23.82	23.82	23.82
Special reader visit fee AH	155.77	155.77	155.77	155.77	155.77
Time switch adjust	23.82	23.82	23.82	23.82	23.82
Customer transfer BH	23.82	23.82	23.82	23.82	23.82
Customer transfer AH	155.77	155.77	155.77	155.77	155.77
Disconnection (incl de-energisation after non-payment) BH	59.91	59.91	59.91	59.91	59.91
Disconnection (incl de-energisation after non-payment) AH	181.73	181.73	181.73	181.73	181.73
Service truck visit BH	130.82	130.82	130.82	130.82	130.82
Service truck visit AH	319.55	319.55	319.55	319.55	319.55
Wasted truck visit BH	130.82	130.82	130.82	130.82	130.82
Wasted truck visit AH	319.55	319.55	319.55	319.55	319.55
Switching service	75.91	75.91	75.91	75.91	75.91
Service truck visit - each add 15 min BH	29.00	29.00	29.00	29.00	29.00
Service truck visit - each add 15 min AH	36.59	36.59	36.59	36.59	36.59
Meter test single phase	109.86	109.86	109.86	109.86	109.86
Meter test single phase AH	183.73	183.73	183.73	183.73	183.73
Meter test single phase additional meter	40.95	40.95	40.95	40.95	40.95
Meter test multi phase	274.64	274.64	274.64	274.64	274.64
Meter test multi phase AH	369.50	369.50	369.50	369.50	369.50
Meter test multi phase additional meter	159.77	159.77	159.77	159.77	159.77
Meter test CT BH	-	-	-	-	-
Meter test CT AH	-	-	-	-	-
Meter investigation BH	-	-	-	-	-
Meter investigation AH	-	-	-	-	-

Metering services for unmetered supplies	0.86	1.07	1.09	1.14	1.16
Solar PV connection – BH	NA	NA	NA	146.00	146.00
Solar PV connection – AH	NA	NA	NA	NA	NA

Table 23.8: CitiPower's prices for Fee Based Services

Revenue

Paragraph 15.2(a)(iii) of the RIN requires CitiPower to provide information about its revenues from Fee Based Services for each year of the current regulatory control period. This information is provided in Table 23.9 with actual data used for 2006-08 and estimates used for 2009-10.

	$000's (real 2010)				
	Actual			Forecast	
Name of service	2006	2007	2008	2009	2010
Reconnection fee BH	61	63	84	97	116
Reconnection fee AH	14	9	63	73	87
Reconnection fee (same day) BH	-	-	-	-	-
Special reader visit fee BH	835	870	1,156	1,335	1,600
Special reader visit fee AH	4	3	18	20	24
Time switch adjust	-	-	-	-	-
Customer transfer BH	1,220	1,271	1,688	1,950	2,336
Customer transfer AH	328	217	1,516	1,752	2,098
Disconnection (incl de-energisation after non-payment) BH	21	54	54	62	75
Disconnection (incl de-energisation after non-payment) AH	10	38	33	38	45
Service truck visit BH	426	359	520	563	632
Service truck visit AH	86	39	58	46	39
Wasted truck visit BH	-	-	-	-	-
Wasted truck visit AH	-	-	-	-	-
Switching service	-	-	-	-	-
Service truck visit - each add 15 min BH	112	39	36	20	12
Service truck visit - each add 15 min AH	13	5	6	3	2
Meter test single phase	62	44	31	22	16
Meter test single phase AH	-	-	-	-	-
Meter test single phase additional meter	1	-	-	-	-
Meter test multi phase	11	22	13	14	16
Meter test multi phase AH	-	-	-	-	-
Meter test multi phase additional meter	-	-	-	-	-
Meter test CT BH	-	-	-	-	-
Meter test CT AH	-	-	-	-	-
Meter investigation BH	-	-	-	-	-
Meter investigation AH	-	-	-	-	-
Metering services for unmetered supplies	42	53	66	65	70
Solar PV connection – BH	NA	NA	NA	105	219
Solar PV connection – AH	NA	NA	NA	NA	NA

Table 23.9: CitiPower's revenues for Fee Based Services

Evidence costs not compensated elsewhere

Paragraph 15.2(a)(viii) of the RIN requires CitiPower to provide evidence that the existing costs of its Fee Based Services are not compensated elsewhere.

CitiPower's Regulatory Accounts include a template for *'Excluded Services and Other Activities'*, which reports information about direct and indirect costs and revenues. This template distinguishes between public lighting and other Excluded Services, but does not distinguish between what in the future will be Quoted Services and Fee Based Services.

The *'Excluded Services and Other Activities'* template in the 2008 Regulatory Accounts shows that total Excluded Services costs (net of grid fees and public lighting) were $19.265 million whereas the Excluded Services revenues were $16.169 million. This information (as with the rest of the Regulatory Accounts) has been prepared in accordance with the ESCV's *Guideline No. 3 Regulatory Accounting Information Requirements Final Decision December 2006*. The principles for the attribution and allocation of costs are reflected into CitiPower's accounting system. CitiPower's chart of accounts classifies all costs and revenues by general ledger account numbers, which map to reporting categories on the balance sheet and profit and loss statement. Each cost or revenue transaction is also assigned to a profit centre. Each cost item is also assigned a function code and, in some cases, an activity type. CitiPower's Regulatory Accounts are externally audited each year.

The 2008 Regulatory Accounts show that CitiPower is currently under-recovering its costs for Excluded Services. This reflects the fact that its Excluded Services charges are not based on a build up of CitiPower's current costs. Rather, as noted above, CitiPower applies charges that were historically levied by the SECV, with certain adjustments.

On this basis, it is clear that the existing costs of CitiPower's Excluded Service are not compensated elsewhere.

23.2.3 Next regulatory control period

Charging methodology

Paragraphs 15.2(a)(vii) and 15.2(b)(i) of the RIN require CitiPower to provide information about the methodologies and assumptions used to derive its proposed charges for Fee Based Services in the next regulatory control period.

In developing its charges for Fee Based Services, CitiPower has applied the following staged process:

- estimating a bottom up charge by the defining the scope of the task and fully costing all the activities;

- applying a top down check of each services' revenue and costs as reported in the Regulatory Accounts;
- where the top down analysis is significantly different from the bottom up analysis, the top down approach has been used to establish the charges;
- for Service Truck Visit, Meter Test and Meter Investigation tasks the proposed increase has been capped at a reasonable level.

CitiPower has applied real labour escalation to the labour component of each charge.

Application of control mechanism

Clause 6.8.3(c) of the Rules requires CitiPower's Regulatory Proposal to demonstrate the application of the control mechanism for Fee Based Services that is detailed in the AER's Framework and Approach paper and to provide necessary supporting information.

Section 3.7.8 of the AER's Framework and Approach paper provides that a price cap form of control will apply to Fee Based Services in the next regulatory control period. This involves:

- setting price caps for each Fee Based Service for the first year of the next regulatory control period based on either a bottom up or top down approach; and
- determining a price path for the price caps on a CPI-X basis for years two to five of the next regulatory control period.

CitiPower has applied the AER's control mechanism for Fee Based Services by:

- using a bottom up approach to determine the price caps for various Fee Based Services for the first year of the next regulatory control period. This applies to the services: Disconnection, Reconnection, Special Reading, various Meter testing, Meter investigation and PV Installation. This is described in the *'Methodology'* section above; and
- using a top down approach to determine the price caps for various Fee Based Services for the first year of the next regulatory control period. This applies to the services: Wasted attendance – not DNSP fault, Service truck activities, Supply abolishment, Fault response – not DNSP fault, and various Meter testing.

Unit costs

Paragraph 15.2(a)(xi) of the RIN requires CitiPower to provide information about the proposed unit cost inputs that it has used to calculate its proposed charges for Fee Based Services in the current regulatory control period.

CitiPower's unit costs for Fee Based Services are detailed in Table 23.10.

[redacted]

Table 23.10: CitiPower's unit costs for Fee Based Services

CitiPower has developed its unit rates from a bottom up approach for various Fee Based Services by adding the contractor costs and the base labour rates from PNS and CHED Services for back office and front office activities. Applied to the labour rates are a pro rata of:

- overheads attributable to PNS;
- pro rated fleet and property charge; and
- overheads attributable to CitiPower.

CitiPower has developed its unit rates from a top down approach for various Fee Based Services by applying CPI and a labour escalator to the current cost inputs .

Indicative prices

Paragraph 15.2(a)(v) of the RIN requires CitiPower to provide information about the indicative prices for its Fee Based Services for each year of the next regulatory control period. This information is provided in Table 23.11.

	$'s (real 2010)				
	Forecast				
Name of service	2011	2012	2013	2014	2015
Reconnection fee (incl customer transfer) BH	18.31	22.90	27.50	27.85	28.12
Reconnection fee (incl customer transfer) AH	63.45	90.62	117.80	118.15	118.41
Reconnection fee (same day) BH	21.81	28.15	34.50	34.85	35.12
Special reader visit fee BH	18.31	22.90	27.50	27.85	28.12
Special reader visit fee AH	Service is not provided After Hours				
Time switch adjust	Service will not provided				
Customer transfer BH	To charge 'Reconnection BH' fee				
Customer transfer AH	To charge 'Reconnection AH' fee				
Disconnection (incl de-energisation after non-payment) BH	18.49	23.18	27.88	28.23	28.49
Disconnection (incl de-energisation after non-payment) AH	Service is not provided After Hours				
Service truck visit BH	207.12	222.91	246.24	279.20	324.46
Service truck visit AH	414.59	446.21	492.91	558.89	649.50
Wasted truck visit BH	173.71	186.95	206.52	234.16	272.12
Wasted truck visit AH	173.71	186.95	206.52	234.16	272.12
Switching service	-	-	-	-	-
Service truck visit - each add 15 min BH	-	-	-	-	-
Service truck visit - each add 15 min AH	-	-	-	-	-
Meter test single phase	207.01	222.79	246.11	279.05	324.30
Meter test single phase AH	487.63	497.57	508.14	526.15	539.73
Meter test single phase additional meter	80.09	86.19	95.22	107.96	125.46
Meter test multi phase	307.27	330.70	365.31	414.21	481.36
Meter test multi phase AH	587.23	599.17	611.87	633.56	649.90
Meter test multi phase additional meter	106.75	114.89	126.92	143.90	167.23
Meter test CT BH	524.14	534.80	546.14	565.50	580.09
Meter test CT AH	568.07	579.61	591.89	612.88	628.68
Meter investigation BH	331.61	338.39	345.59	357.84	367.07
Meter investigation AH	357.14	364.42	372.17	385.36	395.30
Metering services for unmetered supplies	1.21	1.31	1.44	1.64	1.90
Solar PV connection – BH	304.55	310.88	317.62	328.84	337.33
Solar PV connection – AH	319.56	326.19	333.25	345.03	353.94

Table 23.11: CitiPower's indicative prices for Fee Based Services

Evidence costs not compensated elsewhere

Paragraph 15.2(a)(viii) of the RIN requires CitiPower to provide evidence that the future costs of its Fee Based Services are not compensated elsewhere.

CitiPower will apply its Cost Allocation Method to directly attribute, and allocate, costs between Standard Control Services, Alternative Control Services and Negotiated Distribution Services in the next regulatory control period. The principles for the attribution and allocation of costs will be reflected into CitiPower's accounting system in the same manner as currently occurs.

The costs for Alterative Control Services will then be recovered through Public Lighting Services, Fee Based Services or Quoted Services.

CitiPower has provided an Excel workbook as Attachment 3 to this Regulatory Proposal that demonstrates how it has built up the costs attributable to its Fee Based Services for each year of the next regulatory control period. Separate methodologies have been developed for recovering the costs of Public Lighting Services and Quoted Services.

On this basis, CitiPower's future costs of its Fee Based Services will not be compensated elsewhere.

Justification of different charges between customers

Paragraphs 15.2(a)(xii) and 15.2(b)(vi) of the RIN require CitiPower to provide information to justify different charges being applied for different classes of customers.

CitiPower proposes continuing its current practice of differentiating charges to customers for its Fee Based Services depending on whether the services are provided during, or after, business hours. This reflects the fact that there are differences in CitiPower's labour costs during these time periods – in particular, overtime is payable after business hours.

CitiPower also proposes continuing its current practice of applying different charges for:

- service cable pulled down by high load depending on the nature of the cable. The different charges reflect the nature and complexity of the work that CitiPower needs to undertake to restore the cables;
- meter accuracy testing and investigation depending on the type of meter. The different charges reflect the nature and complexity of the work that CitiPower needs to undertake to test and investigate different types of meters; and
- PV installations depending on the type of connection.

23.3 Quoted services

23.3.1 Nature of services

Paragraph 15.2(a)(i) of the RIN requires CitiPower to describe its Quoted Based Services. This information is provided in Table 23.12.

Quoted Based Service	Description
Emergency recoverable works (ie emergency works where customer is at fault and immediate action needs to be taken by the DNSP)	This charge relates to the costs of emergency works that are required to restore CitiPower's distribution network to its standard operating level following an incident caused by a customer.
Damage to overhead service cables caused by high load vehicles	This charge applies to the cost of repairing overhead service cables that have been damaged by high load vehicles.
High load escorts	This charge applies to the cost of lifting overhead lines to allow high load vehicles to pass along roads.

Table 23.12: CitiPower's quoted services

CitiPower notes that, as discussed in Chapter 3 of this Regulatory Proposal, it is proposing that amend the list of Quoted Services proposed by the AER in its Framework and Approach Paper as detailed in Table 23.13.

Service	AER's indicative classification in Framework and Approach paper	CitiPower's proposed classification
Auditing of design and construction	Alternative Control Service – Quoted Service	Standard Control Service
Specification and design enquiry	Alternative Control Service – Quoted Service	Standard Control Service
Damage to overhead service cables caused by high load vehicles	Alternative Control Service – Fee Based Service	Alternative Control Service – Quoted Service
High load escorts – lifting overhead lines	Alternative Control Service – Fee Based Service	Alternative Control Service – Quoted Service

Table 23.13: Differences between AER's indicative, and CitiPower's proposed, quoted services classification

23.3.2 Current regulatory control period

Charging methodology

Paragraph 15.2(a)(vi) of the RIN requires CitiPower to provide information about the methodologies and assumptions used to derive its charges for Quoted Services in the current regulatory control period. CitiPower notes that these services are classified by the ESCV as Excluded Services under the 2006-10 EDPR.

CitiPower's methodology for developing its charges for Quoted Services in the current regulatory control period involves recovering the costs of both labour and materials. Unlike the charges for Fee Based Services, the charges for Quoted Services are developed on a case by case basis in order to meet the specific needs of the customer. CitiPower therefore does not post its charges in advance for its Quoted Services.

CitiPower quantifies its labour costs for each Quoted Service by:

- identifying the tasks involved in performing the Quoted Service;
- quantifying the time that each task will take;
- identifying the types of personnel that will be required to undertake each task, based on the skills required;
- quantifying the number of personnel that are required to undertake each task; and
- applying a labour rate for each type of personnel required. The basis for the calculation of these labour rates is discussed under *'Unit Costs'* below.

CitiPower quantifies its material costs, where applicable, for each Quoted Service by:

- identifying the tasks involved in performing the Quoted Service;
- identifying the type and number of materials that are required for each task; and
- applying a materials rate for each type of material required. The basis for the calculation of these material rates is discussed under *'Unit Costs'* below.

Unit costs

Paragraphs 15.2(a)(ix) and 15.2(a)(x) of the RIN require CitiPower to provide information about the unit cost inputs used to calculate existing charges if available.

The nature of quoted services is such that they vary for each individual customer. On this basis, it is impractical for CitiPower to provide details of its Quoted Service unit costs.

[redacted]

Table 23.14: CitiPower's unit costs for Quoted Services (per hour)

[redacted]

Table 23.15: CitiPower's unit costs for Quoted Services (per job)

CitiPower has developed its unit rates for Quoted Services by taking the base labour and material rates from PNS and applying pro rated:

- overheads attributable to PNS;
- pro rated fleet and property charge; and
- overheads attributable to CitiPower.

Customers or jobs

Paragraph 15.2(a)(ii) of the RIN requires CitiPower to provide information about the number of customers or jobs for its Quoted Services for each year of the current regulatory control period. This information is provided in Table 23.16 with actual data used for 2006-08 and estimates used for 2009-10.

	Customer numbers				
	Actual			Forecast	
Name of service	2006	2007	2008	2009	2010
Emergency recoverable works BH	88	46	9	12	12
Emergency recoverable works AH					
Damage to overhead service cables caused by high load vehicles – BH	0	0	0	0	0
Damage to overhead service cables caused by high load vehicles – AH	0	0	0	0	0
High load escort BH	NA	NA	NA	NA	NA
High load escort AH					

Table 23.16: CitiPower's customers or jobs for Quoted Services

Prices

Paragraph 15.2(a)(iv) of the RIN requires CitiPower to provide information about its prices for Quoted Services for each year of the current regulatory control period.

The nature of quoted services is such that they vary for each individual customer. On this basis, it is impractical for CitiPower to provide details of its Quoted Service prices.

Revenue

Paragraph 15.2(a)(iii) of the RIN requires CitiPower to provide information about its revenues from Quoted Services for each year of the current regulatory control period. This information is provided in Table 23.17 with actual data used for 2006-08 and estimates used for 2009-10.

	$000's (real 2010)				
	Actual			Forecast	
Name of service	2006	2007	2008	2009	2010
Emergency recoverable works BH Emergency recoverable works AH	1,438	651	321	148	413
Damage to overhead service cables caused by high load vehicles – BH	-	-	-	-	-
Damage to overhead service cables caused by high load vehicles – AH	-	-	-	-	-
High load escort BH High load escort AH	NA	NA	NA	NA	NA

Table 23.17: CitiPower's revenues for Quoted Services

Evidence costs not compensated elsewhere

Paragraph 15.2(a)(viii) of the RIN requires CitiPower to provide evidence that the existing costs of its Quoted Services are not compensated elsewhere.

CitiPower's existing costs associated with Quoted Services are treated in the same manner as Fee Based Services and, for the same reasons as explained in section 23.2.2 are not compensated elsewhere.

23.3.3 Next regulatory control period

Charging methodology

Paragraphs 15.2(a)(vii) and 15.2(b)(i) of the RIN require CitiPower to provide information about the methodologies and assumptions used to derive its proposed charges for Quoted Services in the next regulatory control period.

CitiPower intends continuing to apply its current methodology for developing its charges for Quoted Services, which is described in section 23.2.2 of this Regulatory Proposal (using the unit costs for the next regulatory control period).

CitiPower has provided at Attachment 4 to this Regulatory Proposal its Alternative Control Pricing Model, which details the calculations of its proposed charges for Quoted Services. No consultants' reports were used to derive these proposed charges.

Application of control mechanism

Clause 6.8.3(c) of the Rules requires CitiPower's Regulatory Proposal to demonstrate the application of the control mechanism for Quoted Services that is detailed in the AER's Framework and Approach paper and to provide necessary supporting information.

Section 3.7.8 of the AER's Framework and Approach paper provides that a price cap form of control will apply to Quoted Services in the next regulatory control period. This involves:

- setting price caps for each Quoted Service for the first year of the next regulatory control period based on either a bottom up or top down approach; and
- determining a price path for the price caps on a CPI-X basis for years two to five of the next regulatory control period.

CitiPower has applied the AER's control mechanism for Quoted Services by:

- determining the price caps that are to apply to the labour and material rates that it will use to determine its charges for Quoted Services; and
- applying a CPI-X adjustment to the labour and material rates for years two to five of the next regulatory control period.

Unit costs

Paragraph 15.2(a)(xi) of the RIN requires CitiPower to provide information about the proposed unit cost inputs that it has used to calculate its proposed charges for Quoted Services in the current regulatory control period.

CitiPower has developed its unit costs for Quoted Services for the next regulatory control period in the same manner as it did for the current regulatory control period, as described in section, which is described in section 23.3.2 of this Regulatory Proposal.

The unit rates for the next regulatory control period are detailed in Table 23.18.

[redacted]

Table 23.18: CitiPower's future unit costs for Quoted Services (per hour)

Indicative prices

Paragraph 15.2(a)(v) of the RIN requires CitiPower to provide information about the indicative prices for its Quoted Services for each year of the next regulatory control period.

As noted above, the nature of quoted services is such that they vary for each individual customer. On this basis, it is impractical for CitiPower to provide details of its Quoted Service prices. CitiPower instead refers to the hourly rates for Quoted Services outlined in Table 23.19.

	$'s per hour (real 2010)				
	Forecast				
Name of service	2011	2012	2013	2014	2015
Emergency recoverable works BH	130.04	132.66	135.44	140.25	143.87
Emergency recoverable works AH	150.98	154.02	157.25	162.83	167.03
Damage to overhead service cables caused by high load vehicles - Single Phase - BH	117.36	119.724	122.24	126.58	129.84
Damage to overhead service cables caused by high load vehicles - Multi Phase - AH	129.05	131.65	134.41	139.18	142.77
High load escort BH	130.04	132.66	135.44	140.25	143.87
High load escort AH	150.98	154.02	157.25	162.83	167.03

Table 23.19: CitiPower's future prices for Quoted Services (per hour)

Evidence costs not compensated elsewhere

Paragraph 15.2(a)(viii) of the RIN requires CitiPower to provide evidence that the future costs of its Quoted Services are not compensated elsewhere.

CitiPower's future costs associated with Quoted Services will be treated in the same manner as Fee Based Services and, for the same reasons as explained in section 23.2 are not compensated elsewhere.

Justification of different charges between customers

Paragraphs 15.2(a)(xii) and 15.2(b)(vi) of the RIN require CitiPower to provide information to justify different charges being applied for different classes of customers.

The AER noted in its Framework and Approach paper that:

> *'The Victorian DNSPs provide a range of services on a quoted fee basis to retailers and customers. The nature and scope of these services are specific to individual retailers or customer's needs, and therefore the cost of providing the services cannot be estimated without first understanding the retailer's or customer's requirements. This means a DNSP must set individual prices for these services after they have been requested. It would not be appropriate to set a generic fixed fee in advance for the provision of these types of services.'*[83]

The charges that are applied for Quoted Services will therefore necessarily differ between customers, although the same set of unit rates will be applied in calculating all charges.

Median and mean time for Quoted Services

Paragraphs 15.3 of the RIN seeks information on the median and mean time to complete each Quoted Service over the current regulatory control period.

CitiPower is not able to provide information on the median and mean time to complete its Quoted Service. This is because:

- CitiPower does not keep records of the time taken in the current regulatory control period to complete each of its Quoted Services; and
- there is no such thing as a *'standard'* Quoted Service, as, by definition, the nature and scope of each service is unique to the individual circumstances of the customer requiring the service. This was recognised by the AER in its Framework and Approach Paper.

As a result, just as it would be inappropriate to try to set a generic fixed fee in advance for the provision of Quoted Services, so too it would be inappropriate to try to specify a median and mean time period for the completion of these services.

[83] AER, Framework and approach paper for Victorian electricity distribution regulation - CitiPower, Powercor, Jemena, SP AusNet and United Energy - Regulatory control period commencing 1 January 2011, May 2009, page 54

23.4 Allocation of costs

23.4.1 Appropriate allocation of costs

Paragraphs 15.2(b)(iii)-(v) of the RIN require CitiPower to provide information about the allocation of costs, including overheads, between services and to explain how the charges, and terms and conditions, for each service are based on the cost of providing the service.

As noted above, CitiPower will apply its proposed Cost Allocation Method to directly attribute, and allocate, costs between Standard Control Services, Alternative Control Services and Negotiated Distribution Services in the next regulatory control period. The principles for the attribution and allocation of costs will be reflected into CitiPower's accounting system in the same manner as currently occurs.

The costs for Alterative Control Services will then be recovered through Public Lighting Services, Fee Based Services or Quoted Services. This is done through the development and application of unit rates, as described above.

The unit rates include overhead costs for PNS and CitiPower as well as fleet and property costs. The unit rates are used in developing the Annual Revenue Requirement for Public Lighting Services and the posted charges for Fee Based Services and the individually determined charges for Quoted Services.

The charges, and terms and conditions, for each service are based on the cost of providing the service because:

- the proposed Cost Allocation Method is used to allocate costs to Alternative Control Services;
- the unit rates that are developed for Alternative Control Services are designed to recover the costs that relate to these services; and
- the unit rates are applied in developing the Annual Revenue Requirement for Public Lighting Services and the charges for Fee Based and Quoted Services.

23.4.2 Shared assets

Paragraph 15.2(b)(ii) of the RIN requires CitiPower to provide information about how costs for shared assets are allocated between Standard Control Services and each Alternative Control Services.

CitiPower's shared assets mainly relate to fleet. These costs are allocated to the unit rates that apply to Public Lighting, Quoted and Fee Based Services, in accordance with the proposed Cost Allocation Method.

24. NEGOTIATING FRAMEWORK

This Chapter provides information in relation to CitiPower's Negotiating Framework and addresses the requirements of the Rules.

24.1 Rules' requirements

Clause 6.7.5(a) of the Rules requires CitiPower to prepare a Negotiating Framework that sets out the procedure it will follow during negotiations with any person who wishes to receive a negotiated distribution service, as to the terms and conditions for the provision of the service.

Clause 6.7.5(c) of the Rules details the information that must be specified in CitiPower's Negotiating Framework.

Clause 6.7.5(d) of the Rules requires that the Negotiating Framework must not be inconsistent, where relevant, with rules 5.3, 5.4A and 5.5 and any other relevant requirements of Chapter 6 of the Rules.

Clause 6.7.5(e) of the Rules requires CitiPower and service applicants to comply with the requirements of the Negotiating Framework.

Clause 6.7.6 of the Rules details requirements in relation to the treatment of confidential information.

Clause 6.8.2(c)(5) of the Rules requires CitiPower to include its proposed Negotiating Framework in this Regulatory Proposal.

The AER must consider CitiPower's proposed Negotiating Framework in accordance with clause 6.12.3(g) and (h) of the Rules.

24.2 Proposed Negotiating Framework

CitiPower's proposed Negotiating Framework is included at Attachment C0139 of this Regulatory Proposal.

Table 24.1 details how CitiPower considers that its proposed Negotiating Framework complies with, and gives effect to, the requirements of clauses 6.7.5 and 6.7.6 of the Rules.

Clause of Rules	Clause of the proposed Negotiating Framework giving effect to the Rules' requirement
6.7.5(c)(1)	2.1
6.7.5(c)(2)	3.2
6.7.5(c)(3)	3.3
6.7.5(c)(4)	4.2
6.7.5(c)(5)	6.1, 6.3, Table 1
6.7.5(c)(6)	9.1
6.7.5(c)(7)	10
6.7.5(c)(8)	5.1
6.7.5(c)(9)	5.2
6.7.5(c)(10)	8.1
6.7.5(d) (See also 6.7.2(b))	1.2
6.7.5(e) (See also 6.7.2(a)(1))	1.1
6.7.6(a)(1)	3.4(a)
6.7.6(a)(2)	3.5(a)
6.7.6(b)(1)	4.5(a)
6.7.6(b)(2)	4.6(a)

Table 24.1: Compliance of CitiPower's proposed Negotiating Framework

25. CONFIDENTIAL INFORMATION

Clause 6.8.2(c)(6) of the Rules requires CitiPower to provide as part of its Regulatory Proposal an indication of the parts of the Regulatory Proposal it claims to be confidential and wants suppressed from publication on that ground. This Chapter sets out this information.

CitiPower claims confidentiality in respect of:

- Tables 1.1 and 1.2 of the Regulatory Proposal, being the adjustments made to reported operating and capital costs;
- the penultimate row of Table 6.6 (*'West Melbourne Demand Management'*) and Table 6.15 of the Regulatory Proposal, titled *'West Melbourne Demand Side Management Services 2011-15'*;
- Tables 22.2 to 22.6 (inclusive) of the Regulatory Proposal, being information in respect of CitiPower's dealings with other entities;
- Tables 23.10, 23.14, 23.15 and 23.18, being the unit costs of Fee Based and Quoted Services;
- each of the attachments identified in Chapter 30 of the Regulatory Proposal as *'confidential'*. This includes the completed regulatory templates included as Attachments C1000 and C1100 of the Regulatory Proposal.

The reasons confidentiality is sought in respect of these parts of the Regulatory Proposal are set out below.

The information identified above has been given to the AER in confidence and accordingly, by reason of section 44AAF(1) of the *Trade Practices Act 1974* and section 18 of the NEL,[84] the AER is required to take all reasonable measures to protect the information from unauthorised use or disclosure.

CitiPower notes that the obligation to take all reasonable measures to protect information from unauthorised use or disclosure also extends to the information that has been compulsorily acquired by the AER through its RIN.

As a result, CitiPower expects that any information provided to the AER in confidence, and any information provided to the AER in response to the AER's RIN, as part of or as an attachment to this Regulatory Proposal will not be disclosed by the AER, except as authorised by section 44AAF of the Trade Practices Act or Division 6 of Part 3 of the NEL.

[84] Section 18 of the NEL provides that section 44AAF of the *Trade Practices Act 1974* has the effect, for the purposes of the NEL, Regulations and Rules, as if it formed part of the NEL.

25.1 Confidential attachments

Tables 1.1, 1.2, 22.2 to 22.6, 23.10, 23.14, 23.15 and 23.18 contain commercially sensitive information of CitiPower's dealings with other entities, including information as to other entity's margins.

25.2 Forecasts in respect of West Melbourne Terminal Station

In Table 6.15 of the Regulatory Proposal, CitiPower has provided the forecast fees it would be expected to incur in relation to demand side management services for the West Melbourne Terminal Station over the next regulatory control period. This information forms the basis for calculating the step change specified in the penultimate row of Table 6.6.

The information contained in the penultimate row of Table 6.6 and in Table 6.14 is commercially sensitive. The negotiations with the proposed third party supplier of the demand side management services for the West Melbourne Terminal Station have not yet been finalised. Accordingly, CitiPower is concerned that disclosing the information would have an adverse impact on CitiPower's ability to negotiate fees more favourable than the forecast cost.

25.3 Confidential attachments

Each of the attachments identified in Chapter 30 of this Regulatory Proposal as '*confidential*' are not publicly available and contain either intellectual property or information that is commercially sensitive, including:

- information about CitiPower's assets and operational management;
- information about CitiPower's system limitations and constraints and operational performance and risks;
- information about CitiPower's suppliers;
- information about CitiPower's unit rates and costs; and
- commercially sensitive findings of external consultants.

In respect of the completed regulatory templates included as Attachments C1000 and C1100 to the Regulatory Proposal, CitiPower is concerned that the disclosure of the information in respect of 2011-15 would adversely affect CitiPower's ability to negotiate effectively with third parties. Specifically, disclosure of the information would provide third party suppliers with more information as to CitiPower's willingness and ability to pay than would otherwise be available and thus would limit CitiPower's ability to negotiate favourable terms.

26. CERTIFICATION OF REASONABLENESS OF ASSUMPTIONS

NATIONAL ELECTRICITY RULES

CLAUSE S6.1.1(5) AND S6.1.2(6)

CERTIFICATION OF REASONABLENESS OF KEY ASSUMPTIONS THAT UNDERLIE CAPITAL EXPENDITURE AND OPERATING AND MAINTENANCE EXPENDITURE FORECASTS

The Directors of CitiPower Pty ACN 064 651 056 hereby certify that the key assumptions which:

1. underlie:

   a) the proposed capital expenditure forecast as set out and included in CitiPower's building block proposal; and

   b) the proposed operating and maintenance expenditure forecast as set out and included in CitiPower's building block proposal; and

2. are also set out and included in CitiPower's building block proposal, are reasonable.

Signed:

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Peter Tulloch

CHAIRPERSON   dated this 30 of November of 2009

27. STATUTORY DECLARATION

NATIONAL ELECTRICITY LAW

SECTION 28M(d)

STATUTORY DECLARATION

I, Shane Augustus Breheny,

of 40 Market Street Melbourne,

being an officer, for the purposes of the Corporations Act, of CitiPower Ltd ACN 064 651 056 ('CitiPower') do solemnly and sincerely declare that the response of CitiPower regarding the information required to be provided, prepared, kept or maintained as specified in the Australian Energy Regulator's ('AER') regulatory information notice ('Notice') dated Monday, 12 October 2009 is true and accurate:

1. in accordance with the requirements of the Notice; and
2. is accurate and in all material respects can be relied upon to assess the regulatory proposal provided by and to make distribution determinations for CitiPower.

I acknowledge that this declaration is true and correct and I make it in the belief that a person making a false declaration is liable to the penalties of perjury.

Declared at Melbourne in the State of Victoria

this 30th day of November 2009

SHANE BREHENY

SA Breheny

Signature

Before me:

Signature

Address

Anthony Kampus
40 Market Street, Melbourne 3000
~~An Australia Legal Practitioner within~~ the meaning of the Legal Profession Act 2004

(The witness must print their name, address and their authority under section 107A of the *Evidence Act 1958* to witness a statutory declaration)

28. MATERIAL PROGRAMS JUSTIFICATION

Paragraph 3.9 of the RIN requires CitiPower to provide information in relation to its each material program in the next regulatory control period. Material projects are set out below by sub-category of capital expenditure

28.1 Network

RIN reference	CBD security of supply
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, three main options were considered to address the need to upgrade the security of supply to Melbourne's central business district (CBD), being:
3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi)	1. redevelopment of the Brunswick Terminal Station (BTS) and the BQ substation (recommended option); 2. establishment of new CBD terminal and zone substations; and 3. embedded generation and non-network solutions.
3.9(a)(iii) 3.9(b)(ix)(1) 3.9(b)(ix)(2)	In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing option' was not considered as the Essential Services Commission of Victoria (ESC) has made an upgrade to the security of supply for the Melbourne CBD a requirement of the *Electricity Distribution Code* (the Code). Each of the project options investigated are discussed below in turn
	Option 1 – Redevelopment of the BTS and the BQ substation (recommended) Option 1 involves: • the redevelopment of the BTS to be a 66kV supply point for the CBD and the redevelopment of the BQ substation (previously the BSBQ substation) into a high capacity 66kV substation; • installing additional 66kV circuit breakers and underground cables to existing CBD substations; and • integrating with the connection to a new 66kV supply point at the BTS. The works are in accordance with the CBD Security Plan approved by the ESC, in accordance with clause 3.1A of the Victorian Electricity Distribution Code (the Code). There were four sub options considered for the cable route connection BTS to the BQ substation, being: • two conductor routes, each circuit using two cables per phase; • two conductor routes, each circuit using one cables per phase; • two independent routes with part over head conductor and part under ground conductor; and • one conductor route for both circuits using one cable per phase for each circuit. Customer and public consultation was undertaken during the development of the project. There were no objections. Option 1 allows for: • the CBD security of supply to redevelop the existing CBD substations into a fully switched topology to enhance the security of supply; and

- greater load transfer capability of the BQ substation between terminal stations.

The CBD security of supply project (option 1) will be carried out in two stages, co-ordinated with the Metro 2012 capacity upgrade project, being:

- Stage 1 – Installation of a single 66kV circuit from BTS to VM and VM to BQ, and establish 19 x 66kV GIS circuit breakers at the existing VM zone substation to convert it to a fully switched 66kV zone substation; and
- Stage 2 – Establishment of 7 x 66kV GIS circuit breakers at the existing W switching substation, a single 66 kV circuit from BQ to VM and 2 x 66 kV circuits from BQ to W and reroute the existing 66kV cable from VM-W to VM-WA.

The project complements the Metro 2012 project. The two projects were initially developed as an overall security and capacity driven network development scenario.

Option 2 – Establishment of new CBD terminal and zone substations

Option 2 involves the establishment of a new 220/66kV terminal station at the existing BSBQ substation site (renamed to the BQ substation). Option 2 requires:

- a 220kV cable to be connected from the BTS to the RTS via the BQ substation;
- 66 kV substation augmentations similar to those conducted for Option 1; and
- 66kV feeders from the new BQ terminal station to the existing CBD substations.

The N-1 Secure was achieved in option 2 by improved 66kV transfer capability, elimination of most multiple transformer ended feeder configurations and conversion to a fully switched topology and reduced reliance on the West Melbourne Terminal Station (WMTS).

Option 3 – Embedded generation and non-network solutions

Embedded generation and non-network solutions were considered. These included the location of generation within or close to the CBD and demand side management in the case of an outage event.

In response to the 2007 CBD security of supply regulatory test, no responses offering the required amount of embedded generation were received.

A report by SKM, investigating the options available to relieve the capacity and supply, discussed the implementation of demand side management. The SKM report found that approximately 245 MVA would need to be turned off, almost without warning to the customer, in order to be viable. In practice such an approach is not feasible.

Costs and benefits of each option considered

In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN, a cost benefit analysis was undertaken, the results of which are as follows:

- option 1:
  - provides a large capacity increase and the site was most suitable for development with no permitting and planning issues since it is currently used as a 66kV substation;
  - will also provide the N-1 Secure supply for the CBD for the same reasons as listed in Option 2; and
  - is the least cost option compared with option 2;
- option 2 significantly increased the supply capacity but the cost was much greater than for option 1. Additionally, there was potential for planning and permitting issues to arise with the local council; and

	• option 3 is not considered feasible. Further, NERA Economic Consulting conducted a regulatory test in 2007 that considered the CBD security of supply and Metro 2012 projects combined. The regulatory test concluded that: • the projects proposed in option 1 passed the test with a net benefit of $4 million over all the tested scenarios; and • option 2 returned a net benefit of -$19.1 million over all the tested scenarios. The works have been shown to be more beneficial if both the capacity and security works are conducted rather than just the security works. *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project or the alternative options considered.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for investment* In response to paragraph 3.9(b)(i), an upgrade of the security of supply to the Melbourne CBD is needed as it has been made a requirement of the Code by the ESC. In 2001, supply to the Melbourne CBD was interrupted on two separate occasions. These outages highlighted a lack of transfer capability and a reliance on the WMTS. A subsequent review found that had the network been designed to a higher security standard then the effects of these outages would have been reduced. The ESC subsequently made an upgrade to the security of supply for the CBD a requirement of the Code. SKM was engaged by CitiPower to investigate options available to relieve the capacity and supply. The design, options and costs were further independently scrutinised by the ESC's consultant, Maunsell. The CBD security of supply project (option 1) has been found to be the most efficient and prudent method to achieve compliance with the revised Code. *Reasons for why the project was chosen over the alternative options* In response to paragraph 3.9(b)(ii) of the RIN, option 1, the redevelopment of the BTS and the BQ substation was recommended for the following reasons: • it provides a large capacity increase and the site was most suitable for development with no permitting and planning issues since it is currently used as a 66kV substation; • it will also provide the N-1 Secure supply for the CBD; and • it is the least cost option compared with option 2.
3.9(b)(x) 3.9(b)(viii) 3.9(b)(vii)	Explanation of estimation process In response to paragraph 3.9(b)(viii) of the RIN, the CBD security of supply project was initially costed at $52.4 million in 2006 by SKM. The cost was based on a high level functional scope of works and historical expenditure incurred by CitiPower for similar plant items. These costs were then escalated for CPI and materials cost increases to reach a total of $64.8 million over the duration of the project. The escalated project costs were presented to the Board on May 2008. The forecast cost in the forthcoming regulatory period is based on further project scoping and quotes for similar jobs and best-available estimates that were received for the Metro 2012 project and work at VM and W. The CBD Security of Supply 66kV cabling costs were based on the approved estimates for the BTS to BQ cables which are part of the Metro 2012 project and were estimated by Bayside who is an independent consultant. Unit prices per km were used, plus allowances were made for using single trenches and higher costs for working in the CBD. The station works were

	based on similar costs for BQ and information provided by other consultants (eg Maunsell for the VM upgrade). In response to paragraph 3.9(b)(vii) of the RIN, the CBD security of supply project is a major project developed to increase the security of supply to the CBD – it is not possible to substitute opex for capex for this project. In response to paragraph 3.9(b)(x) of the RIN, the estimated expenditure is detailed in Table 1 below.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Other considerations In response to paragraph 3.9(b)(xi) of the RIN, there are no other considerations.

RIN reference	Docks area zone substation upgrade
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii) 3.9(b)(ix)(1) 3.9(b)(ix)(2)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, three main options were considered to meet the load growth in the area supplied by the Docks Area (DA) zone substation, being: 1. Conversion of the DA zone substation into a high-capacity 66/11 kV CBD-style zone substation (recommended option); 2. establishment of a new zone substation; and 3. alternate network solutions. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing option' was not considered as: • the forecast maximum demand for 2013 far exceeds the station N-1 rating; and • demand is forecast to continue to increase placing significant energy at risk and creating the potential for unserved energy. Each of the project options investigated are discussed below in turn. *Option 1 – Conversion of the DA zone substation into a high-capacity 66/11 kV CBD-style zone substation (recommended)* Option 1 involves converting the existing DA zone substation into a high-capacity 66/11 kV CBD-style zone substation with (ultimately) 3 x 55MVA transformers. This project is forecast to run for a period of four years from 2012 through to 2015. *Option 2 – Establishment of a new zone substation* Option 2 requires the establishment of a new zone substation to meet forecast load growth. This would include the procurement of a suitable site and finding easements for 66kV cables and conductors from West Melbourne Terminal Station (WMTS). *Option 3 – Alternate network solutions* Alternate network solutions were considered, including: • using cogeneration up to 2MVA; • load transfers at 11kV (up to 12MVA from DA to WG); and • increasing load transfer capability with adjacent substations. However, these are only short term solutions, deemed to only be suitable until 2011/2012.

	The use of cogeneration also has other technical issues, including fault level contribution, and requires a proponent who wishes to connect at that location. *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN, a cost benefit analysis of the project options was undertaken, the results of which are as follows: • option 1, the conversion of the DA zone substation into a 66kV zone substation is the least cost; • deferment measures do not actually address the capacity issue; and • increasing the capacity of the existing 22kV/11kV substation, as contemplated by option 3, is not considered efficient. Transformers could be sized to be 55MVA but they would be physically much bigger. The 22kV buses would have problems carrying the current as would the transformer cables. The resultant load on the lines from the terminal station would require at least two new 22kV lines. Further, increasing the capacity of the zone substation and not converting it to 66kV is not consistent with the system design principles practiced in CitiPower to achieve the required increase in capacity required. This would lead to an inefficient network design. Other factors that CitiPower considered in making its decision on which option would be most efficient to meet the future demand of the area included: • enquiries from the Docks to develop the area as a consequence of the Channel Deepening Project just completed. This will increase the load beyond the current forecast. • the expected end of life of the DA No2 transformer, which is planned for replacement in 2015. Therefore there are synergies with the asset replacement program. A consideration of the relative benefits and costs of option 1 led to this option being selected as the preferred option. The most favourable alternative option is to establish a new zone substation within the Docks area (option 2) with the associated subtransmission infrastructure. While the benefits of this option 2 exceed the benefits of option 1, the cost of this alternative option 2 is estimated to be greater than the cost of the proposed solution of converting DA into a 66kV zone substation and the greater benefits of option 2 are not considered to justify this greater cost. *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the recommended project or the alternative options considered.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for investment* In response to paragraph 3.9(b)(i), this project is required in order for CitiPower to meet the load growth in the Docks area supplied by the 22/11kV DA zone substation. The Docks area encompasses parts of Docklands and North Melbourne. The growth rate for the last seven years has been 6.2 per cent and the forecast growth rate will average approximately 6.0 per cent. According to the 2008 DSPR, the DA zone substation will have 6,055MWh and 1,831 hours at risk in 2013. The forecast maximum demand for 2013 is 45.3MVA, which far exceeds the station N-1 rating of 28.8MVA. The plan to augment the DA zone substation into a high-capacity 66kV/11kV zone substation is further supported by load growth forecasts from the Docks two main power users: Patricks and DP World (formerly PandO). A confidential report prepared by Hyder Consulting for the Port of Melbourne indicates that by 2020 Patricks demand will increase two-fold while DP World's demand will increase three-fold. Limited transfers are available and additional permanent transfers away from the DA zone substation to the WG zone substation are planned, but these will only provide short term solutions. The load is forecast to continue to grow and a new zone substation is required. The

	forecast load growth, energy at risk and the potential unserved energy is sufficient reason for the project not to be deferred. *Reasons for why the project was chosen over the alternative options* In response to paragraph 3.9(b)(ii) of the RIN, option 1, conversion of the DA zone substation into a high-capacity 66/11 kV CBD-style zone substation, was recommended for the following reasons: • it was the least cost technically feasible option; • deferment measures do not actually address the capacity issue; • increasing the capacity of the 22kV/11kV substation, as contemplated by option 3, is not considered efficient; and • there are synergies with the asset replacement program.
3.9(b)(x) 3.9(b)(viii) 3.9(b)(vii)	Explanation of estimation process In response to paragraph 3.9(b)(viii) of the RIN, a high-level estimate for the DA zone substation has been prepared based on similar projects. At this stage the project has not been submitted for approval so detailed costing has not yet been completed. In response to paragraph 3.9(b)(vii) of the RIN, to achieve the capacity increase that is required, capital works are required. It is not possible to replace this program with opex. In response to paragraph 3.9(b)(x) of the RIN, the estimated expenditure is detailed in Table 1 below.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Other considerations In response to paragraph 3.9(b)(xi) of the RIN, there are no other considerations.

RIN reference	BTS – CW – B – RTS subtransmission loop
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii) 3.9(b)(ix)(1) 3.9(b)(ix)(2)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, five main options were considered to reduce the risk that is posed by the forecast load growth and excess energy at risk at the Richmond Terminal Station (RTS), being: 1. construction of a subtransmission line between the Brunswick Terminal Station (BTS) and the RTS (recommended option); 2. permanent transfer of supply of two zone substations from RTS 66kV to Malvern terminal station (MTS); 3. demand Reduction; 4. embedded generation; and 5. establishment of a new terminal station. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing option' was not considered as demand at the RTS is expected to reach a level that will put it at 28.5 per cent overload by 2014. Each of the project options investigated are discussed below in turn.

	Option 1 - Construction of a subtransmission line between the BTS and the RTS (recommended) Option 1 requires the construction of a subtransmission line between the BTS and the RTS, via the Collingwood zone substation (CW), North Richmond zone substation (NR) and Collingwood zone substation (B). This subtransmission line would provide load transfer capability between the terminal stations and reduce the load at risk at the RTS by transferring load at the CW, NR and B zone substations to the BTS under normal conditions. This is a significant project planned for implementation between Jan 2014 and Dec 2016. *Option 2 - Permanent transfer of supply of two zone substations from the RTS 66kV to the MTS* Option 2 requires the establishment of a third transformer at MTS with associated bus work. *Option 3 – Demand Reduction* Option 3 involves achieving a level of demand reduction sufficient to reduce the expected load at risk to acceptable levels. *Option 4 - Embedded generation* No proponents have come forward during the consultation period to offer this as a solution. No proponents are expected to come forward in time to reduce the risk. *Option 5 – Establishment of a new terminal station* This project would involve the establishment of a new terminal station. *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN, the cost benefit analysis showed that the annual cost for the recommended project (option 1) is less than the value of unserved energy to the customer. Further details can be found in the 2008 Transmission Connection Planning Report, including the value of expected unserved energy versus the value of the capital augmentation cost. The results of the cost benefit analysis concluded that: • the level of demand reduction that could be employed through option 3 is insufficient for the expected loads at risk; • no proponents of embedded generation (option 4) have come forward during the consultation period and no proponents are expected to come forward in time to reduce the load at risk; and • the cost of option 2 and option 5 is greater than that of option 1, the recommended option. *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project or the alternative options considered.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for investment* In response to paragraph 3.9(b)(i), the RTS to BTS sub transmission loop is required to address forecast demand growth and energy at risk. Demand at RTS is expected to reach a level that will put it at 28.5 per cent overload by 2014. The energy at risk at the 50th percentile demand is 7,450 MWh or $512 million in customer interruption cost (this is the energy that would not be delivered if a failure of a major terminal station component occurred at the time of maximum demand). The expected unserved energy at the 50th percentile demand is 64.7 MWh, or $4.4 million in customer interruption cost (this is the probability weighted energy that would not be delivered if a failure of a major terminal

	station component occurred at the time of maximum demand). *Reasons for why the project was chosen over the alternative options* In response to paragraph 3.9(b)(ii) of the RIN, option 1, the construction of a subtransmission line between the BTS and the RTS, was recommended as: • the level of demand reduction that could be employed under option 3 is insufficient for the expected loads at risk; • no proponents of embedded generation (option 4) have come forward during the consultation period and no proponents are expected to come forward in time to reduce the load at risk; and • it presented the least cost of the remaining alternative options, being option 2 and option 5.
3.9(b)(x) 3.9(b)(viii) 3.9(b)(vii)	Explanation of estimation process In response to paragraph 3.9(b)(viii) of the RIN, the cost estimate for connecting the NR-B-CW loop into the BTS is based on the costs for the BTS-BQ cables, which have been estimated to a detailed level as part of the CBD security of Supply and Metro 2012 projects. The following methodology was used: • $4.13 million/km (Direct cost for BTS-BQ); • 0.8 (reduction) factor for civil works away from the CBD; • 3km approximate distance; with • the project cost = 4.13 x 0.8 x 3= $9.9 million. Note: $1,982,000 of the $9.9 million is forecast to be spent in 2016. In response to paragraph 3.9(b)(vii) of the RIN, since this project is a capacity augmentation, it is not possible to replace capex with opex or vice versa. In response to paragraph 3.9(b)(x) of the RIN, the estimated expenditure is detailed in Table 1 below.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Other considerations In response to paragraph 3.9(b)(xi) of the RIN, there are no other considerations.

RIN Reference	Metro 2012 capacity upgrade
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, three main options were considered to address the increasing load growth and to enable reduction of energy at risk at: • 3 x terminal station connections (WMTS 66kV and 22kV, and RTS 66kV) • 5 x 66/11kV zone substations • 8 x 66kV sub-transmission lines • 3 x 22kV sub-transmission lines. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing option' was not considered. *Options considered*

3.9(b)(ix)(1) 3.9(b)(ix)(2)	Option 1 - BTS and BQ (recommended) The Metro 2012 project involves redeveloping the Brunswick Terminal Station (BTS) into a 66kV supply point and the redevelopment of the Bouverie-Queensbury substation (BQ) into a high capacity 66/11 kV substation. The new BQ zone substation will ultimately provide 180MVA of transformation capacity. Additionally, there will be several 66kV underground circuits installed to connect BTS, BQ and other zone substations. New 11 kV feeders installed from BQ will be required to connect the load to the new BQ, thus reducing load at risk at these adjacent zone substations. The 11kV feeder augmentations are included as separate, but accompanying, projects to the Metro 2012 project. This project is planned to be undertaken in two stages. Details of the stages are: Stage 1. Stage 1 will redevelop BTS and establish the high capacity BQ substation with gas insulated switchgear and two transformers. One 66kV cable will be installed from BTS to BQ. Stage 2. Stage 2 will establish the third transformer at BQ and the construction of the second 66kV cable from BTS direct to BQ. The project complements CBD Security of Supply project. The two projects were initially developed as an overall security and capacity driven network development scenario. *Alternative options* SKM was engaged by CitiPower to investigate options available to relieve the capacity and supply security issues that emerged in 2001 when electricity supply to the CBD was interrupted on two separate occasions. The design, options and costs were further independently scrutinised by the ESC's consultant, Maunsell. SKM considered option 1 and the alternative options, a summary of each alternative option is as follows: Option 2 – CBD terminal and zone substations (not recommended) This option involved the establishment of a new 220/66kV terminal station at the existing BSBQ site. This option would require a 220kV cable to be connected from BTS to RTS via BSBQ. The 66 kV substation augmentations would be similar to those conducted for option 1. There would also be 66kV feeders from the new BSBQ terminal station to the existing CBD substations. Option 3 – Embedded generation and non-network solutions (not recommended) Embedded generation and non-network solutions were considered. These included location of generation within or close to the CBD and demand side management in the case of an outage event. *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN a cost benefit analysis was undertaken. Option 1 - BTS and BQ (recommended) The benefit for Option 1 is greater load transfer capability between terminal stations, and reduces the load at risk at adjacent zone substations. The costs for Option 1 were initially forecasted at $66.2m in 2007. The costs were based on a high level functional scope of works and historical expenditure incurred by CitiPower for similar plant items. The project budget was prepared to a level of +/- 20% based on CitiPower practice. The forecast cost in the forthcoming regulatory period is based on detailed design and refined

	project scope. Rather than build two BTS-BQ circuits in stage one of Metro 2012, a BTS-VM-BQ 66kV loop will be created. Also Stage 1 will only install two 55MVA 66kV/11kV transformers. The 11kV feeder works to offload adjacent zone substations have now been established as separate projects. A Regulatory Test for the establishment of the Brunswick Terminal Station was conducted in 2008, with the recommended option indicating the highest net benefit of $1,100 M. Option 2 – CBD terminal and zone substations (not recommended) The benefit for Option 2 is greater load transfer capability between terminal stations, and reduces the load at risk at adjacent zone substations. However, the benefit was not as great as Option 1. The costs for Option 2 were greater than Option 1. Option 3 – Embedded generation and non-network solutions (not recommended) Option 3 was not feasible so no cost benefit analysis was conducted. *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project or the alternative options considered.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for investment* In response to paragraphs 3.9(b)(i) of the RIN, the Metro 2012 project is required to meet increasing load growth and to enable reduction of energy at risk at: • 3 x terminal station connections (WMTS 66kV and 22kV, and RTS 66kV) • 5 x 66/11kV zone substations • 8 x 66kV sub-transmission lines • 3 x 22kV sub-transmission lines The load growth has been driven by major development and re-development projects occurring within inner Melbourne and the Docklands. Precise details concerning the energy at risk and the cost to the business of the energy at risk, broken down to substation level, can be found in the *Project Metro 2011 Justification Statement document*. A second driver for the Metro 2012 project is the implementation of the CBD Security of Supply (CBD SoS) project. CitiPower has an obligation under the Electricity Distribution Code (the Code) to improve the CBD supply security. The BTS upgrade, which is part of the Metro 2012 scope of works, establishes the 66 kV supply point for the CBD which is required for the CBD SoS project to be implemented. This means that the Metro 2012 project must go ahead in order for CitiPower to comply with the Code. *Reasons for why chosen project was chosen over the alternative options* In response to paragraphs 3.9(b)(ii) of the RIN, a Regulatory Test for the establishment of the Brunswick Terminal Station was conducted in 2008, with the recommended option indicating the highest net benefit of $1,100 M. In response to the Regulatory Test, there were no non-network solutions proposed. Option 1 – BTS and BQ (recommended) Option 1 allows for the CBD SoS to redevelop the existing CBD substations into fully switched topology to enhance the security of supply. Option 1 allows for greater load transfer capability between terminal stations.

	There were four sub options considered for the cable route connection BTS to BQ. These were: • Two separate routes, each cable trench capable of two circuits using one cable per phase for each circuit; • Two separate routes, each cable trench capable of one circuit using one cable per phase for each circuit; • Two independent routes with part over head conductor and part under ground conductor; and • One route (single trench) for both circuits using one cable per phase for each circuit. The fourth option was the recommended sub-transmission component of Metro 2012 (Stage 1). A second trench will be constructed as part of stage 2 to provide the second 66kV circuit from BTS to BQ and the future 66kV circuit from BTS-W. Option 2 – CBD terminal and zone substations (not recommended) Option 2 was not recommended. The capacity increase was not as substantial as for option 1 but the cost was much greater. Further, there was potential for planning and permitting issues to arise with the local council. Option 3 – Embedded generation and non-network solutions (not recommended) Neither of these options was feasible. There were no proponents for embedded generation, and the implementation of embedded generation would also cause issues with the fault levels and could have negative environmental effects (exhaust emissions).
3.9(b)(viii) 3.9(b)(vii) 3.9(b)(x)	Estimated expenditure In response to paragraph 3.9(b)(viii) of the RIN, a high-level estimate for this project has been prepared based on a high level functional scope of works and historical expenditure incurred by CitiPower for similar plant items. The project budget was prepared to a level of +/- 20% based on CitiPower practice. The forecast cost in the forthcoming regulatory period is based on detailed design and refined project scope. Rather than build two BTS-BQ circuits in stage one of Metro 2012, a BTS-VM-BQ 66kV loop will be created. Also Stage 1 will only install two 55MVA 66kV/11kV transformers. The 11kV feeder works to offload adjacent zone substations have now been established as separate projects. The Metro 2012 was estimated internally with inputs from external service providers. Bayside provided input into the BTS-BQ cable estimates and comparisons of OH/UG vs. fully UG and different trenching options. Other contractors were involved in the BQ zone substation quote, such as civil contractors for the building works and AG Coombs for the fire suppression, approximate prices for transformers, GIS CBs and other plant. Network Services collated the inputs from external sources and determined the total project cost. In response to paragraph 3.9(b)(x) of the RIN, the estimated expenditure is detailed in Regulatory Template 4.2. *Capex and opex substitution* In response to paragraph 3.9(b)(vii) of the RIN, the Metro 2012 project is a major project developed to increase the capacity of supply to the CBD. It is not possible to substitute opex for capex for this project.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Identify all other relevant considerations. In response to paragraph 3.9(b)(xi) of the RIN, there are not other relevant considerations.

<table>
<tr><th>RIN reference</th><th>CP-CUB Site: Customer Connection Augmentation</th></tr>
<tr><td>3.9(a)(i),
3.9(b)(iii)
3.9(b)(iv)

3.9(a)(ii)
3.9(b)(v)
3.9(b)(vi)

3.9(a)(iii)
3.9(b)(ix)(1)
3.9(b)(ix)(2)</td><td>
Project and alternative options description
In response to paragraph 3.9(a)(i) of the RIN, only two options were considered.
In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing option' was not considered as the project was customer initiated and under the Electricity Distribution Code (the Code) CitiPower has an obligation to offer customers connection.
Option 1 – Redevelopment of the BTS and the BQ substation (recommended)
This project involves augmentation to enable supply of 29MVA to the former Carlton and United Brewery (CUB) site in Swanston Street, Melbourne. The project scope has been developed based on information provided by the property developers, Grocon.
The estimated customers demand based on CitiPower's assessment of usage types is 21,544KVA. CitiPower is happy to provide a breakdown of preliminary load information relating to this overall development.
The project scope involves three separate programs of works:

zone substation works
distribution substation installation
HV feeder installations.

Zone Substation augmentation works
These works involves modifying the existing 66kV switching substation at W to a new 66/11kV new zone substation with a 2 x 55MVA capacity . The proposed station would include 2 x 55MVA 66/11kV Transformers, a 66kV GIS switchboard, 11KV ring bus, capacitor banks, NER's and 11kV circuit breakers with underground feeder exits.
Distribution Substation installations
The project involves the development of following new distribution substations and HV switching station.

Bldg 1 will have a 2 x 1000 kVA Tx substation
Bldg 2 will have a 2 x 1000 kVA Tx substation
Bldg 3 will have a 2 x 1000 kVA Tx substation
Bldg 4 (basement substation) will have a 2 x 2000 kVA Tx substation and includes a switching station with cables to the hi rise substation
Bldg 4 (Hi Rise) substation will contain 8 x 500 kVA Transformers
Bldg 5 will have a 2 x 1500 kVA Tx substation
Bldg 6 will have a 3 x 2000 kVA Tx substation
Bldg 7 (Retail 2) will have a 3 x 2000 kVA Tx substation

7 HV feeders in total to enable integration with other substations and HV cable risers in other buildings.
HV Feeder works
These works involve installation of the following new feeders and associated items
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	• 7 HV feeders in total • 4 x new 11kV feeders from zone substation W • 3 x new 11kV Feeders from zone substation BQ • Eight new 125mm and two new 63mm conduits from CUB switching station to zone substations W and BQ • New fibre optic cable and distribution SCADA. *Timing* The timing of the work is dependent upon direction from the customer. The customer's current indication is demand for a 4MVA supply of electricity at the start of 2013, increasing to 16MVA in mid-2013 and then 28MVA in 2014. Adhering with this timeline requires CitiPower to commence works in 2012. *Option 2 – Establishment of a new zone* substation (not requested) An alternative option to the proposed scope of works is to establish a new zone substation within the customer's development and augment CitiPower's sub-transmission network to supply the new zone substation. This alternative requires significant zone substation works and augmentation of CitiPower's sub transmission network to install the sub-transmission cables. This option may be considered should the customer's requirements change to include significant on-site cogeneration, as this option would dictate a different sub-transmission connection. This project is scoped on the basis of no-cogeneration, which CitiPower understands is the customer's current intention for the site. *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN, no cost benefit analysis has been conducted for this project. This is because the only alternative option to Option 1, being the Co-Gen option, is not suitable given the customer's requirements and has not been requested by the customer. The benefits and costs of Option 1 are detailed below (see 'Project justification' and 'Estimated expenditure'). *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project or the alternative options considered.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for investment* In response to paragraph 3.9(b)(i), this customer connection augmentation project is necessary to enable the proposed re-development of the former CUB site. CitiPower has a legitimate supply request from a developer with a proven track record of delivering projects of the size proposed. The project thus cannot be deferred. *Reasons for why the project was chosen over the alternative options* In response to paragraph 3.9(b)(ii) of the RIN, the customer requested option 1. There is no alternate option for supply (other than the Co-Gen option) considered at this stage, given the current information from the client and the timeframes available to us. The customer has not requested the Co-Gen option.
3.9(b)(viii) 3.9(b)(vii) 3.9(b)(x)	Explanation of estimation process In response to paragraph 3.9(b)(viii) of the RIN, the costs for this project are based on recent similar types of works that have been carried out by CitiPower. CitiPower has significant recent experience installing new substations and feeders within similar style buildings in the

	Melbourne CBD, including extensive developments in the docklands and other landmark buildings in the CBD. Zone substation augmentation costs for this project are based on CitiPower's experience with zone substation SB which is currently under construction. Zone substation installation costs are based on CitiPower's standard design installed in other CBD buildings. HV feeder and civil construction costs are based on CitiPower's experience constructing similar installations. CitiPower notes the following regarding these calculations: • Directly attributed costs are CitiPower's direct costs of the distribution substation and HV feeder works. • Customer's incremental costs do not include the zone substation augmentation. Instead an allowance for upstream augmentation is made through the marginal cost of reinforcement which is based on $/MVA amount. The $/MVA applied is CitiPower's current zone substation MCR, reduced by 40% as an allowance for the outcome of the decision from the AER in respect to CitiPower's MCR's. • Incremental revenue figure above is based on the kW allowances outlined in the CUB Site Electricity Requirements spreadsheet In response to paragraph 3.9(b)(vii) of the RIN, the CUB project is a major connection project and as a consequence it is not possible to substitute opex for capex. In response to paragraph 3.9(b)(x) of the RIN, the estimated expenditure is detailed in Table 1 below.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Other considerations In response to paragraph 3.9(b)(xi), there are no other considerations relevant to this project.

28.2 SCADA

RIN Reference	Enhanced Zone Substation Monitoring and Control
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii) 3.9(b)(ix)(1) 3.9(b)(ix)(2)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, CitiPower was not able to identify any alternatives options for this project as on the basis that no feasible alternatives are available. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing' option was not considered because CitiPower believes that it is prudent and efficient for it to enhance its Zone Substation Monitoring and Control. This project is consistent with CitiPower's goals as documented in its Communications Strategy 2009-2014. The Enhanced Zone Substation Monitoring and Control project, relates to investment in increased substation monitoring and automation investments over the 2011-15 regulatory control period. The enhanced zone substation monitoring and control sub-program involves the continual enhancement of substation control and monitoring and will extend to transformers and capacitor banks where monitoring and control does not currently exist for all substations *Costs and benefits* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN, no formal cost benefit analysis study was undertaken however, CitiPower has assessed that the benefits of undertaking the Enhanced Zone Substation Monitoring and Control project include; • better voltage management during planned and unplanned switching;

	• improved quality of supply to customers; • better management and visibility in high load scenarios; • enablement of management of the system fault levels; • improved data capture for further analysis; • improved fault analysis; and • enablement of integration with CitiPower's asset management systems No cost benefit analysis was conducted for the project as a whole because each individual substation system upgrade will undergo an option and cost benefit analysis to ensure the most appropriate option is chosen and that it aligns with CitiPower's communications strategy. *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for investment* In response to paragraph 3.9(b)(i) of the RIN, CitiPower has a range of electronic devices, at various electrical stations, which are remotely accessed via the Ethernet network. These devices are used for remote control or monitoring of plant in electrical stations. This project will enable CitiPower to expand the control and monitoring functionality of these electronic devices throughout its stations over the 2011-15 regulatory control period, focusing on transformers and capacitor banks in order to better manage emerging system constraints. Once DMS is implemented and operational, the remote control and monitoring functionality of these devices will primarily be used for day to day operational needs and the collection of data for on going asset maintenance management, including population of the GIS and SAP databases. Since the existing devices are aged or outdated, they must be upgraded to devices which are compatible with the new SCADA system and its communications hardware, software and protocols. *Reasons for why the project was chosen over the alternative options* In response to paragraph 3.9(b)(ii) of the RIN, the enhanced zone substation monitoring and control project was chosen as it was the only feasible project identified and it aligns with CitiPower's communications strategy.
3.9(b)(x) 3.9(b)(viii) 3.9(b)(vii)	Explanation of estimation process In response to paragraph 3.9(b)(viii) of the RIN, the costs associated with the enhanced zone substation monitoring and control project have been estimated on the basis of current average costs of undertaking similar projects in the current regulatory control period. CitiPower plans to undertake between 2 and 4 projects a year in stations where enhanced monitoring and control presents the greatest business benefit. No benchmarking of expenditure has been undertaken in relation to the cost of this project. In response to paragraph 3.9(b)(vii) of the RIN, substituting capital for operating expenditure or vice versa is not possible for this program as new technologies are required to interface with new DMS and SCADA systems.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Other considerations No other considerations are relevant.

RIN Reference	Station security monitoring
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii) 3.9(b)(ix)(1) 3.9(b)(ix)(2)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, CitiPower was not able to identify any alternative options that would provide the extent of substation visibility required, without putting a person in potential danger by physically needing to be present at the substation. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing' option was not considered because CitiPower believes that increasing substation visibility is consistent with improving safety of employees and the general public. This is because over recent years there has been an increase in copper theft. The removal of copper, through theft, results in the removal of earths and the possible disengagement of electric protection schemes. This places the copper thief at risk of electric shock and increases the safety risks of CitiPower's employees. Copper theft can be better managed through investment in security monitoring. *Options considered* The only project option considered in this case was the station security monitoring project. Investment in station security monitoring will improve the visibility and security of CitiPower's key stations. *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN, no formal cost benefit analysis study was undertaken. However, CitiPower has assessed that the benefits of investing in station security monitoring include reduced safety risks to CitiPower's employees. *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for investment* In response to paragraph 3.9(b)(i) of the RIN, the CitiPower notes that Investment in station security monitoring will improve the visibility and security of CitiPower's key stations. In particular, investment in station security monitoring will allow CitiPower to respond appropriately to faults or security breaches by utilising the deployed fibre based Ethernet network. The deployment of Ethernet infrastructure provides the opportunity to improve station visibility and security. This is important because over recent years there has been an increase in copper theft. The removal of copper, through theft, results in the removal of earths and the possible disengagement of electric protection schemes. This places the copper thief at risk of electric shock and increases the safety risks of CitiPower's employees. The camera technology that will be installed as part of CitiPower's Station security monitoring program will provide an extensive range of vision throughout the stations in which they are installed. This will enable CitiPower to remotely confirm on site activities and visually investigate faults prior to a field operator arriving at the station. CitiPower was not able to identify any other remote technology options that are able to provide the extent of the visibility required to monitor its substations *Reasons for why the project was chosen over the alternative options* In response to paragraph 3.9(b)(ii) of the RIN, the Station security monitoring was chosen as it was the only feasible project that would provide the extent of substation visibility required , without putting a person in potential danger by physically needing to be present at the substation.
3.9(b)(x)	Explanation of estimation process

3.9(b)(viii) 3.9(b)(vii)	In response to paragraph 3.9(b)(viii) of the RIN, the costs associated with station security monitoring are based on vendor quotes for the required high resolution cameras. These vendor quotes include the cost of installation. No benchmarking of expenditure has been undertaken in relation to the costs of this project. In relation to paragraph 3.9(b)(vii) of the RIN, substituting capital for operating expenditure or vice versa is not possible in this program as the program involves the installation or upgrade of new technology.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Other considerations No other considerations are relevant.

RIN Reference	New fibre installations
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii) 3.9(b)(ix)(1) 3.9(b)(ix)(2)	Project and alternative options description *Options considered* In response to paragraph 3.9(a)(i) of the RIN, two options were considered, being 1. install new fibre optics; or 2. retain the existing copper cables. Wireless solutions were not considered on the basis that no Service Level Agreement (SLA) was available and protection scheme implementations require a direct end to end connection. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing' option was not considered because CitiPower requires a fully functional communications network to allow for the control and monitoring of plant and relays. Each of the project options investigated are discussed in turn below *Option 1 –new fibre installations (recommended)* The new fibre installations project is the selected project. This project relates to the replacement of the existing supervisory cable systems, between substations, with a fibre based system equipment. CitiPower notes that going forward both its protection and SCADA related systems require a fibre or Ethernet interface for full functionality. The installation of optical fibre cables would essentially remove the limits on the distance or speed of data transfer. This program covers communication networks that link substations owned by CitiPower. *Option 2 – retain the existing copper cables* This option is to retain the existing copper cables. The existing copper supervisory cables use Voice Frequency (VF) technology which is outdated and not compatible with the Ethernet protocols and modern equipment functionality and bandwidth requirements. Further, the copper cables limit the distance and speed that digital signals can be sent. *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN, CitiPower conducted a study into the technical attributes and benefits of available Ethernet systems to identify the preferred technology. The outcomes and recommendations from this were then presented to the Capital Investment Committee (CIC). CitiPower determined that for a range of reasons investment in a fibre based system was the

	preferred option. These reasons included: • the increasing cost of maintaining the copper cables associated with retention of the existing copper cables; and • the non-compliance of retention of the existing copper cables with the required functionality of the Communications Strategy 2009-2014. The benefits to CitiPower of upgrading the existing copper supervisory cables to fibre based system, include that it will: • effectively and efficiently remove the data transfer limits imposed by the existing cables; • enable CitiPower to meet the objectives set out in its *Communications Strategy 2009-2014*; • allow the deployment of modern relays when replacing protection schemes; • provide communication bandwidth for modern protocols; • facilitate, through modern equipment, the collection of data from stations; • facilitate the implementation of security monitoring systems; • provide for enhanced SCADA performance and increased data capture; and • facilitate field workers gaining access to corporate networks at stations. The estimated cost of the preferred option is detailed below (see 'estimated expenditure'). *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project.
3.9(b)(i) 3.9(b)(ii)	Project justification In relation to paragraph 3.9(b)(i) of the RIN, CitiPower notes that investment in new fibre installations is necessary to upgrade the communications network to allow for the increased control and monitoring of plant and relays. The existing copper supervisory cables use Voice Frequency (VF) technology which is outdated and not compatible with the Ethernet protocols, modern equipment functionality and bandwidth requirements. The existing copper cables also limit the distance and speed that digital signals can be sent. *Reasons for why the project was chosen over the alternative options* In response to paragraph 3.9(b)(ii) of the RIN, investment in new fibre installations was chosen on the basis of the reasons set out above.
3.9(b)(x) 3.9(b)(viii) 3.9(b)(vii)	Explanation of estimation process In relation to paragraphs 3.9(b)(x) and 3.9(b)(viii) the forecast cost of the program was developed on the basis of current average costs of undertaking similar projects in the current regulatory control period. CitiPower will extend fibre into 2 stations per year to align with the relay replacements and Ethernet deployment requirements. No benchmarking of expenditure has been undertaken in relation to the costs of this project. The forecast annual cost associated with this project is around $0.5m and the total forecast expenditure for the 2011-15 regulatory control period is around $2.5 million. Removal of the copper cables will result in a small reduction in system maintenance operating expenditure. In relation to paragraph 3.9(b)(vii) of the RIN, substituting capital for operating expenditure or vice versa is not possible in this program as the program involves the installation of new technology.
3.9(a)(iv)	Estimated expenditure

	Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Other considerations No other considerations are relevant.

RIN Reference	Installation of DMS field devices
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii) 3.9(b)(ix)(1) 3.9(b)(ix)(2)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, CitiPower was not able to identify any alternative options, other than the installation of DMS field devices that would provide increased monitoring of the distribution network where there is significant load growth and increasing amounts of embedded generation. The installation of DMS field devices will leverage off the implementation of the DMS system where data can be accessed and used in real time. *Options considered* The only project option considered in this case was the installation of DMS field devices. Investment in station security monitoring will improve the visibility and security of CitiPower's key stations. In particular, investment in station security monitoring will allow CitiPower to respond appropriately to faults or security breaches by utilising the deployed fibre based Ethernet network. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing' option was not considered because increased monitoring of the distribution network is increasingly important in light of the increasing network utilisation and the increase in connection of embedded generators to the distribution network. *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN, no formal cost benefit analysis study has been undertaken. :As noted, the installation of DMS field devices will leverage off the implementation of the DMS system where data can be accessed and used in real time. CitiPower's own internal analysis however identified the relative costs and benefits of this project. The benefits are set out above (see 'options considered) and the estimated costs are set out below (see 'estimated expenditure'). *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project.
3.9(b)(i) 3.9(b)(ii)	Project justification Implementation of the DMS will enhance the ability to display and utilise data from field devices providing a real time operational view of the network and allowing network events to be modelled to plan operational switching requirements and provide the best network performance and reliability. The increase in network utilisation and the connection of embedded generators to the distribution network are driving the need for a real time operational view of the network's condition. CitiPower will firstly introduce real time monitoring in small areas of the network characterised by either high peak loads, or a concentration of embedded generation. This is because these areas of the network face a higher risk of potential constraints. CitiPower notes that as the Federal and state incentive frameworks for connection of embedded generators to the distribution network are strengthened, its need to introduce real time monitoring to a greater number of areas in the network will also increase. *Reasons for why the project was chosen over the alternative options* In response to paragraph 3.9(b)(ii) of the RIN, investment in installation of DMS field devices

	project was chosen on the basis that no alternative project options were identified. The installation of DMS field devices will leverage off the implementation of the DMS system where data can be accessed and used in real time.
3.9(b)(x) 3.9(b)(viii) 3.9(b)(vii)	Explanation of estimation process In relation to paragraphs 3.9(b)(x) and 3.9(b)(viii) of the RIN the forecast cost of the program was developed on the basis of: • cost estimates provided by Energy Australia for smart grid - monitoring customer substation loads; and • current average costs of installing remotely monitored fault indicators. No benchmarking of expenditure has been undertaken in relation to the costs of this project. In relation to paragraph 3.9(b)(vii) of the RIN, substituting capital for operating expenditure or vice versa is not possible in this program as the program requires the installation of new technology.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Other considerations No other considerations are relevant.

28.3 IT

RIN Reference	AMI Leveraged Projects
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii) 3.9(b)(ix)(1) 3.9(b)(ix)(2)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, two main options were considered being to increase the functionality of AMI or do nothing. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing option' was considered. Option 1 – AMI leveraged project (recommended) Option 1 involves a program of works. These works include meter outage notification, enhanced load shedding capability, proactive voltage complaint analysis and demand management. These works will leverage the information and communications developed through the AMI project, although these works have not have been included as part of the Victorian AMI review. The program of works is currently scheduled for 2012. Option 2 – Do nothing (not recommended) *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN a cost benefit analysis has been conducted by PWC. PricewaterhouseCoopers (PWC) has undertaken a structured examination of whether the proposed AMI leveraged projects satisfy the capital expenditure objectives, criteria and factors in clause 6.5.7 of the Rules. A copy of PWC's report entitled *Assessment of the Justifiable Need for investment in additional AMI capabilities* has been provided as an attachment to this Regulatory Proposal. The costs and benefits of each option are discussed below (see 'Project justification' and 'Estimated expenditure').

	Contingencies In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for the investment* In response to paragraphs 3.9(b)(i) of the RIN, the AMI leveraged works include developing new capability to: • be able to selectively shed load to an individual customer level. For example, when AEMO directs it to shed load, CitiPower would be able to shed particular customers or locations, while maintaining supply to essential infrastructure such as rail road crossings and traffic lights; • enable network controllers to proactively identify localised faults by linking the network outage management system with AMI outage information. Currently, network operators predominantly rely on customers notifying CitiPower of localised faults. Being able to proactively identify these outages would allow CitiPower's field crews to be dispatched to repair faults. This would shorten the period of time over which the customer is off supply; • collect quality of supply data from individual meters. This will enable proactive diagnosis of typical supply quality issues, such as voltage variations in order to assist resolving matters more quickly; • manage customer demand/load control in real time. For example, instead of shedding load in a particular region completely in times of generation shortfalls, CitiPower would be able to limit individual customer demand, such that all customers could continue to operate their essential appliances; and • collect more accurate localised data to enable CitiPower to make more efficient and prudent network planning decisions. *Reasons for why chosen project was chosen over alternative options* In response to paragraphs 3.9(b)(ii) of the RIN, the do nothing option would result in a missed opportunity to capture the significant number of customer benefits from the AMI leveraged project. Refer to the PWC report entitled *Assessment of the Justifiable Need for investment in additional AMI capabilities* which has been provided as an attachment to this Regulatory Proposal.
3.9(b)(viii) 3.9(b)(vii) 3.9(b)(x)	Estimated expenditure process In response to paragraph 3.9(b)(viii) of the RIN, the estimated expenditure process was conducted in accordance with the IT methodology described in section 5.9.3 of this Regulatory Proposal. In summary, the estimate will be created using current day dollars and will be based on previous IT projects and the experience of the application manager. Closer to the implementation of the project, indicative quotes may be requested from vendors for validation against internal estimates. In response to paragraph 3.9(b)(x), the total forecast cost of the project for the next regulatory control period is detailed in Regulatory Template 4.2. *Substitution of capex for opex* In response to paragraph 3.9(b)(vii) of the RIN, there was no consideration of substituting capex for opex.
3.9(a)(iv)	Estimated expenditure

	Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Identify all other relevant considerations. In response to paragraph 3.9(b)(xi) of the RIN, there are no other relevant considerations.

RIN Reference	CIS-O/V Replacement
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii) 3.9(b)(ix)(1) 3.9(b)(ix)(2)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, two main options were considered to address the redundancy of the Customer Information and Billing System (CIS). These options are the replacement of the CIS or do nothing. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing option' was considered. Option 1 – Replacement of CIS (recommended) Option 1 involves the replacement of the CIS Billing System (CIS) to ensure technology and functionality currency. The discovery phase of this project will commence in 2013 for software selection and finalization of preferred systems and architecture. Implementation project to start in 2014 with delivery to the production environment for CitiPower in 2015. It was originally envisaged that the CIS would be replaced around 2009. However, the introduction of AMI resulted in the project being deferred on the basis that changing the billing systems could potentially increase the risks of delivering the AMI project. Option 2 – Do nothing (not recommended) *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN a cost benefit analysis has not been conducted. An analysis is expected to be completed at the end of 2012. The benefits and costs of the replacement of the CIS are outlined below (see 'Project justification' and 'Estimated expenditure'). *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for the investment* In response to paragraphs 3.9(b)(i) of the RIN, this project should not be deferred because there is a high risk that product support will not be available by 2015 and CitiPower's revenue is dependent on the continued operation of CIS. By 2015, the CIS will be 16 years old and will be well beyond its expected service life. The last vendor-generated release of enhanced functionality was in 2003 and its current owner, Logica, has no plans for further enhancements. CitiPower is one of the last Australian users of the CIS. In the future, a lack of ongoing support could therefore present a risk to CitiPower and the stability of its system could be impaired. *Reasons for why chosen project was chosen over alternative options*

	In response to paragraphs 3.9(b)(ii) of the RIN, CitiPower's initial view is to proceed with this project over the do nothing option because: • the risk to business continuity increases as the product support becomes more problematic; • the existing system and the inherent restrictions on enhancements will not enable the full benefits of the AMI program to be delivered.
3.9(b)(viii) 3.9(b)(vii) 3.9(b)(x)	Estimated expenditure process In response to paragraph 3.9(b)(viii) of the RIN, the estimated expenditure process was conducted in accordance with the IT methodology described in 5.9.3 of this Regulatory Proposal. In summary, the estimate will be created using current day dollars and will be based on previous IT projects and the experience of the application manager. Closer to the implementation of the project, indicative quotes may be requested from vendors for validation against internal estimates. In response to paragraph 3.9(b)(x), the total forecast cost of the project for the next regulatory control period is detailed in Regulatory Template 4.2. *Substitution of capex for opex* In response to paragraph 3.9(b)(vii) of the RIN, there was no consideration of substituting capex for opex. Additional Opex spend cannot mitigate the risks associated with the continued use of this old technology.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Identify all other relevant considerations. In response to paragraph 3.9(b)(xi) of the RIN, this project was previously accepted in the 2006-10 EDPR but was deferred until 2013. It was originally envisaged that the CIS would be replaced around 2009. However, the introduction of AMI resulted in the project being deferred on the basis that changing billing systems could potentially increase the risks of delivering the AMI project. As a consequence, some further minor enhancements were undertaken as part of the AMI project, which were funded through the Victorian AMI review, in order to allow the CIS to manage an AMI rollout efficiently and to extend its system life.

RIN Reference	W Expansion and FR-MP cables extension
3.9(a)(i), 3.9(b)(iii) 3.9(b)(iv) 3.9(a)(ii) 3.9(b)(v) 3.9(b)(vi) 3.9(a)(iii) 3.9(b)(ix)(1)	Project and alternative options description In response to paragraph 3.9(a)(i) of the RIN, three main options were considered to address the forecast demand and security of supply issues in the CBD. In response to paragraph 3.9(b)(iv) of the RIN, a 'do nothing' option was not considered. *Options considered* Option 1 – Waratah Place 66kV switching station converted to zone substation (recommended option) Waratah Place (W) is a future zone substation which is currently just a 66 kV switching station, utilising isolators for the switching. It currently enables the transfer of some load between Richmond Terminal Station (RTS) and West Melbourne Terminal Station (WMTS) in the event of a

3.9(b)(ix)(2)	severe network disruption. As part of the CBD Security of Supply project, the existing seven 66kV isolators are being replaced with seven 66kV GIS CBs to enable faster switching. Waratah Place (W) is planned to be converted from a 66 kV switching station into a zone substation. This development is proposed to be achieved by progressive augmentation during the next regulatory period. The next regulatory period (2011-15) will include the development of the 66kV arrangement, where eight Gas Insulated Switchgear (GIS) Circuit Breakers (CB) will be installed in addition to those that will be installed as part of the CBD SoS project, bringing the total GIS CBs located at W to 15. A double bus, with an arrangement similar to that which will be installed at Victoria Market (VM) zone substation, will also be installed at W. Two sub-transmission cables will then be extended from Flinders/Ramsden (FR)-McIllwraith Place (MP) to W. Once these cables are terminated at W, it will be possible to also supply MP from Brunswick Terminal Station (BTS), as well as the existing supply from Richmond Terminal Station (RTS). This arrangement will increase the capacity and maintain security of supply, consistent with the CBD sub-transmission development plans. *Alternative options considered* CitiPower has considered alternative solutions to meet the forecast demand and security of supply issues. These alternative options were: Option 2 – Transfer load away from FR and MP at 11kV (not recommended) Option 2 involves the transfer of load away from FR and MP at 11 kV to reduce load on the subtransmission cables. This would likely require another zone substation and the costs to install new feeders to transfer the load. Currently the new BQ is forecast to exceed its N-1 rating by the end of the decade. Option 3 – Replace the RTS-FR with higher rated cables (not recommended) Option 3 involves the replacement of the RTS-FR cables with higher-rated cables. These cables are 4.4km long and this would be a much more expensive option. It also fails to improve the subtransmission security of FR and MP. *Costs and benefits of each option considered* In response to paragraphs 3.9(a)(ii) and 3.9(b)(v)-(vi) of the RIN a cost benefit analysis was undertaken to determine the forecast cost and benefits for each of the three options. Option 1 and Option 2 would result in increased capacity and the maintenance of security of supply. However, the costs for option 2 are greater than option 1. The benefits of option 3 are limited and, further, this option fails to improve subtransmission security of FR and MP. *Contingencies* In response to paragraphs 3.9(a)(iii) and 3.9(b)(ix)(1)-(2) of the RIN, no risk based contingencies were included in the forecast costs of the recommended project or the alternative options considered.
3.9(b)(i) 3.9(b)(ii)	Project justification *Need for investment* In response to paragraphs 3.9(b)(i) of the RIN, this project is necessary to meet the forecast load growth and to maintain security of supply to MP. The combined maximum demand at FR and MP zone substations has grown from 145.9MVA in

	2000 to 184.2MVA in 2008. It is forecast to exceed 200MVA by 2015. This load growth has increased the load on the three sub-transmission cables from RTS which supply FR and MP. The load on these cables has reached a critical level, and even though load will be transferred permanently away at the 11kV distribution level from FR and MP to the new Bouverie Queen (BQ) zone substation, this only offers a short-term solution, as continued load growth will require the ability to transfer load at 66kV to provide a longer-term solution. Further, the 3 cables supplying FR and MP are only rated to 720A, or approximately 80MVA each. In an N-1 scenario the cables can only supply approximately 160MVA. The current standard for 66kV cables is to be rated to supply 120MVA each. Three cables from BQ and BTS will supply W to give an N-1 rating of 240MVA. These cables will be utilised to increase the supply capacity to FR and MP via the new GIS CBs. In addition to the increase in capacity, the N-1 secure standard to FR and MP is maintained into the future when the limited support provided by 11kV distribution transfers is consumed. The additional 66kV CBs will provide the flexibility to switch 66kV supply to MP from RTS to BTS thereby providing an equivalent transfer capability and switching time to 11kV distribution transfers. It will also allow the future option of supplying MP permanently from BTS. This project should not be deferred as it addresses the load at risk of the RTS-FR cables and provides security benefits for FR and MP zone substation customers. *Reasons for why chosen project was chosen over alternative options* In response to paragraphs 3.9(b)(ii) of the RIN, the expansion of W and conversion to a zone substation was selected by CitiPower as the preferred option over other alternatives due to the following reasons: • It improves security of supply for FR and MP in consideration of the forecast load growth. • It increases flexibility on the 66kV network, consistent with the CBD Security of Supply objectives. • It has synergies with an existing project, the CBD Security of Supply rebuild of W, and therefore costs can be minimised. • Upgrading the 66kV cables between RTS and FR will be a more expensive option and does not address the security of these lines. Under the risk based deterministic approach, a least cost evaluation was undertaken against alternative options. The only other options would be further transfers away at 11 kV to reduce load at FR and MP. However, this would require another zone substation to receive the transferred load, and would therefore be much more expensive.
3.9(b)(viii) 3.9(b)(vii) 3.9(b)(x)	Estimated expenditure process In response to paragraph 3.9(b)(viii) of the RIN, the costs for this project have been based on costs incurred for recent similar projects undertaken by CitiPower. The CBD SoS project component that is planned for the upgrade of BQ and VM has been used as a basis for the W expansion. The BQ and VM projects have been estimated to a CitiPower Class 2 (+/- 20%) level. The estimate for the sub transmission cables was based on the scope of works and estimates completed for the Metro 2012 and CBD SoS project which are approved projects. The cable cost includes an allowance for a tunnel under W as there is heavy congestion in the area with WA zone substation across the lane. In response to paragraph 3.9(b)(x) of the RIN, the estimated annual costs of the project in each regulatory year are detailed Regulatory Template 4.2. *Substitution of capex for opex*

	In response to paragraph 3.9(b)(vii) of the RIN, no practical substitution of opex for capex could be identified. Capital works are required to achieve the capacity increase. It is not possible to replace this program with opex.
3.9(a)(iv)	Estimated expenditure Please refer to Regulatory Template 4.2.
3.9(b)(xi)	Identify all other relevant considerations. In response to paragraph 3.9(b)(xi) of the RIN, there are no other relevant considerations.

29. STRUCTURE OF RESPONSE TO RIN AND RULES REQUIREMENTS

Response to RIN

RIN paragraph	Regulatory proposal section where addressed
1. General	
1.1(a)	1.1.5
1.1(b)	1.1.6
1.1(c)	1.1.7
1.1(d)	1.1.2 and 29
1.2(a)	1.2
1.2(b)	1.2
1.2(c)	1.2
1.3	9.1, 10.1.3, and 11
2. Classification of services	
2.1	3.2
2.2(a)	Regulatory Templates
2.2(b)	3.3
3. Capital expenditure	
3.1(a)(i)	5.3 and 5.2.12
3.1(a)(ii)	5.3, 5.4.4, 5.5.3, 5.6.4, 5.6.6, 5.7.3, 5.8.3, and 5.9.3
3.1(b)	5.2.1, 5.2.3, 5.2.5 and Regulatory Template 6.4
3.1(c)(i)	5.2.6
3.1(c)(ii)	5.2.12
3.1(c)(iii)	5
3.1(c)(iv)	5.2.5 and Regulatory Template 6.4, 5.4.5, 5.5.4, 5.6.5, 5.7.4, 5.8.4 and 5.9.4
3.1(c)(v)	5.2.8
3.1(c)(vi)	5.2.7
3.1(c)(vii)(1) and (2)	5.2.1
3.1(c)(vii)(3)	5.2.1
3.1(c)(viii)	5
3.2	5.2.9 and Attachment C0034
3.1(a)(i)	5.4.4, 5.5.3, 5.6.4, 5.7.3, 5.8.3, 5.9.3, and 5.9.3
3.1(a)(ii)	5.4.4, 5.5.3, 5.6.4, 5.7.3, 5.8.3 and 5.9.3
3.1(b)	5.2.1, 5.2.6, and 5.4 to 5.9
3.1(c)(i)	5.2.6
3.1(c)(ii)	Attachment C0138
3.1(c)(iii)	5.4.5, 5.5.4, 5.6.5, 5.7.4, 5.8.4, and 5.9.4
3.1(c)(iv)	5.2.5 and Regulatory Template 6.4, 5.4.5, 5.6.5, 5.7.4, 5.8.4 and 5.9.4
3.1(c)(v)	5.2.8
3.1(c)(vi)	5.2.7

RIN paragraph	Regulatory proposal section where addressed
3.1(c)(vii)(1) and (2)	5.2.1
3.1(c)(vii)(3)	5.2.1
3.1(c)(viii)	5
3.3(a)(i)	5.2.1, 5.4.2
3.3(a)(ii)	5.2.7
3.3(a)(iii)	5.4.2
3.3(b)(i) and (ii)	5.2.1, 5.2.7
3.3(b)(iii)	5.4.8 and Regulatory Template 5.2
3.3(c)	5.4.2
3.4(a)(i)	5.2.13
3.4(a)(ii)	5.2.13
3.4(a)(iii)	5.2.13
3.4(a)(iv)	5.2.13
3.4(b)(i) and (ii)	5.2.13
3.4(b)(iii)	5.2.13
3.4(b)(iv)	5.2.13
3.4(c)	5.2.13
3.5(a)(i)	5.2.1, 5.6.2
3.5(a)(ii)	5.6.6
3.5(a)(iii)	5.6.5 and 5.6.6
3.5(a)(iv)	5.6.2
3.5(b)(i)	5.2.1, 5.6.5, and 5.6.6
3.5(b)(ii)	5.2.1, 5.6.5, and 5.6.6
3.5(b)(iii)	5.2.1, 5.6.5, and 5.6.6
3.5(c)(i)	5.6.6
3.5(c)(ii)	5.6.6
3.5(d)	5.6.6 and 5.6.5
3.5(e)	5.6
3.6(a)(i)	5.2.13
3.6(a)(ii)	5.2.13
3.6(a)(iii)	5.2.13
3.6(b)(i)	5.2.13
3.6(b)(ii)	5.2.13
3.6(b)(iii)	5.2.13
3.6(c)	5.2.13
3.6(d)(i)	5.2.13
3.6(d)(ii)	5.2.13
3.6(d)(iii)(1)	5.2.13
3.6(d)(iii)(2)	5.2.13
3.6(d)(iii)(3)	5.2.13
3.6(d)(4)	5.2.13
3.6(d)(5)	5.2.13
3.7(a)(i)	5.7.2, 5.2.1

RIN paragraph	Regulatory proposal section where addressed
3.7(a)(ii)	5.7.4, 5.7.3
3.7(a)(iii)	5.7.5
3.7(a)(iv)	5.7.5
3.7(a)(v)	5.7.5
3.7(a)(vi)	5.7.2
3.7(b)(i)	5.2.1, 5.7.4, and 5.7.5
3.7(b)(ii)	5.2.1, 5.7.4, and 5.7.5
3.7(b)(iii)	5.2.1, 5.7.4, and 5.7.5
3.7(c)	5.7.2, 5.7.4
3.7(d)(i)	5.7.4
3.7(d)(ii)	5.7.5
3.7(e)(i)	5.7.5
3.7(e)(ii)	5.7.5
3.7(e)(iii)	5.7.5
3.7(f)(i)	5.7.5
3.7(f)(ii)	5.7.5
3.7(f)(iii)	5.7.5
3.7(g)(i)	5.7.5
3.7(g)(ii)	5.7.5
3.7(g)(iii)(1)	5.7.5
3.7(g)(iii)(2)	5.7.5
3.7(g)(iii)(3)	5.7.5
3.7(g)(4)	5.7.5
3.7(g)(5)	5.7.5
3.8(a)(i)	5.8, 5.9, 5.9.5
3.8(b)	5.8.4, 5.9.4
3.8(c)(i)	5.9.4
3.8(c)(ii)	5.9.4
3.9 generally	28
3.9(a)(i)	28
3.9(a)(ii)	28
3.9(a)(iii)	28
3.9(a)(iv)	28
3.9(b)(i)	28
3.9(b)(ii)	28
3.9(b)(iii)	28
3.9(b)(iv)	28
3.9(b)(v)	28
3.9(b)(vi)	28
3.9(b)(vii)	28
3.9(b)(viii)	28
3.9(b)(ix)	28
3.9(b)(x)	28

RIN paragraph	Regulatory proposal section where addressed
3.9(b)(xi)	28
3.10(a)	5.10
3.10(b)	5.10
4. Operating and maintenance expenditure	
4.1(a) and 4.2(a)	6.2 and 6.9.3
4.1(a) and 4.2(b)	6.8 and Regulatory Template 6.4, 6.4 (Table 6-2), 6.9.1, 6.5 and Regulatory Template 4.1, and 6.9.3
4.1(a) and 4.2(c)(i)	6.8
4.1(a) and 4.2(c)(ii)	6.12.1 to 6.12.3
4.1(a) and 4.2(c)(iii)	6.2 and 6.9
4.1(a) and 4.2(c)(iv)	6.7
4.1(a) and 4.2(c)(v)	6.6
4.1(a) and 4.2(c)(vi)	6.8 and Regulatory Template 6.4
4.1(a) and 4.2(c)(vii)	6.4 (Table 6-2)
4.1(a) and 4.2(c)(viii)	6.9.3
4.1(a) and 4.2(c)(ix)	6.9.1
4.1(a) and 4.2(c)(x)	6.13
4.1(b) and 4.2(a)	6.10
4.1(b) and 4.2(b)	6.10
4.1(b) and 4.2(c)(i)	6.10
4.1(b) and 4.2(c)(ii)	6.10
4.1(b) and 4.2(c)(iii)	6.10
4.1(b) and 4.2(c)(iv)	6.10
4.1(b) and 4.2(c)(v)	6.10
4.1(b) and 4.2(c)(vi)	6.10
4.1(b) and 4.2(c)(vii)	6.10
4.1(b) and 4.2(c)(viii)	6.10
4.1(b) and 4.2(c)(ix)	6.10
4.1(b) and 4.2(c)(x)	6.10
4.1(c) and 4.2(a)	6.3
4.1(c) and 4.2(b)	6.3
4.1(c) and 4.2(c)(i)	6.3
4.1(c) and 4.2(c)(ii)	6.3
4.1(c) and 4.2(c)(iii)	6.3
4.1(c) and 4.2(c)(iv)	6.3
4.1(c) and 4.2(c)(v)	6.3
4.1(c) and 4.2(c)(vi)	6.3
4.1(c) and 4.2(c)(vii)	6.3
4.1(c) and 4.2(c)(viii)	6.3
4.1(c) and 4.2(c)(ix)	6.3
4.1(c) and 4.2(c)(x)	6.3
4.3(a)	6.9.4
4.3(b)	6.8.4

RIN paragraph	Regulatory proposal section where addressed
4.4(a)	6.9.4 and Attachment C0066
4.4(b)	6.9.4 and Attachment C0066
4.5(a)	6.9.4 and Attachment C0066
4.5(b)	6.9.4 and Attachment C0066
4.5(c)	6.9.4
4.5(d)	6.9.4
4.6(a)	6.14.3
4.6(b)	6.14.4
5. New customer connections and customer contributions	
5.1(a)	5.5.4
5.2(a)	5.5.5 and Regulatory Templates 2.1 and 3.1
5.2(b)(i)	5.5.5
5.2(b)(ii)	5.5.5
5.2(c)	5.5.5
6. Other entities	
6.1	22.1.1
6.2	Figures 22-1 and 22-2
6.3	22.1.2 and 22.1.3
6.4(a)	22.1.5
6.4(b)	22.1.2, 22.1.5, 22.1.6 and Attachment C0053
6.5(a)	22.1.3
6.5(b)	22.1.4
6.5(c)	22.1.4
6.5(d)	22.1.4
6.5(e)	22.1.3
7. Pass-through events	
7.1(a)	12.3.1, 12.3.2 and 12.4
7.1(b)	12.4
8. Weighted average cost of capital	
8.1	15 and 16
8.2	15.9
9. Non-network alternatives	
9.1	8.1
9.2	8.2.1 and 8.2.2
9.3	8.3.1 and 8.3.2
9.4	8.3.1 and 8.3.2
9.5	8.4
10. Efficiency benefit sharing scheme	
10.1(a)(i)	9.2
10.1(a)(ii)	9.3
10.1(a)(iii)	9.4
10.1(a)(iv)	9.6

RIN paragraph	Regulatory proposal section where addressed
10.1(a)(v)	9.6
10.1(b)(i)	9.2
10.1(b)(ii)	9.2
10.1(b)(iii)	6.9.1
10.1(b)(iv)	9.3
10.2	9.6
10.3	9.2
11. Demand and customer number forecasts	
11.1	4.2, 4.3 and Attachment C0005, and 4.4
11.2	4.2, 4.2.1, 4.2.2, 4.3, 4.3.1, 4.3.2, 4.4, 4.4.1, 4.4.2, 5.2.1 and 6.4
11.3	4.2.3, 4.3.3 and 4.4.3
11.4	4.2.4, 4.3.4 and 4.4.4
11.5	4.2.4, 4.2.5, 4.3.4, 4.3.4, 4.4.4 and 4.4.5
12. Unit costs and expenditure escalators	
12.1(a)	7.1.1
12.1(b)	7.1.1 and 7.1.2
12.1(c)	7.1.1
12.1(d)	7.1.1 and 7.1.2
12.2(a)	7.2.1, 7.2.2 and 7.2.3
12.2(b)	7.2.1, 7.2.2 and 7.2.3
12.2(c)	7.2.1, 7.2.2 and 7.2.3
12.2(d)(i)	7.2.1, 7.2.2 and 7.2.3, and Attachments C0041 and C0040
12.2(d)(ii)	7.2.1, 7.2.2 and 7.2.3
12.2(b)(iii)	7.2.1, 7.2.2 and 7.2.3
12.2(b)(iv)	-
12.2(b)(v)	7.3
12.2(b)(vi)	7.4
12.3	7.2.1
13. Utilisation and weighted average remaining life	
13.1(a)	5.4.6, 5.6.6
13.1(b)	5.4.6, 5.6.6
14. Transitional matters	
14.1	21
14.2	21
15. Alternative control services (excluding public lighting services)	
15.1	23
15.2(a)(i)	23.1.1, 23.2.1 and 23.3.1
15.2(a)(ii)	23.1.2, 23.2.2 and 23.3.2
15.2(a)(iii)	23.1.2 (Table 23-3), 23.2.2 (Table 23-8) and 23.3.2 (Table 23-14)
15.2(a)(iv)	23.1.2, 23.2.2 and 23.3.2
15.2(a)(v)	23.1.3 and Attachment C0076, 23.2.3 and 23.3.3
15.2(a)(vi)	23.1.2 and 23.2.2

RIN paragraph	Regulatory proposal section where addressed
15.2(a)(vii)	23.1.3 and Attachment C0076, 23.2.3 and Attachment C0088, and 23.3.3
15.2(a)(viii)	23.1.2, 23.1.3, 23.2.2, 23.2.3, 23.3.2 and 23.3.3
15.2(a)(ix)	23.1.2, 23.2.2 and 23.3.2
15.2(a)(x)	23.1.2, 23.2.2 and 23.3.2 (Table 23-12)
15.2(a)(xi)	23.1.3 and Attachment C0076, 23.2.3 and 23.3.3
15.2(a)(xii)	23.1.3, 23.2.3 and 23.3.3
15.2(b)(i)	23.1.3 and Attachment C0076, 23.2.3 and 23.3.3
15.2(b)(ii)	23.4
15.2(b)(iii)	23.4
15.2(b)(iv)	23.4.1
15.2(b)(v)	23.4.1
15.2(b)(vi)	23.1.3, 23.2.3, 23.3.3
15.3(a)	23.3.3
15.3(b)	23.3.3
16. CBD Security of Supply	
16.1	5.4.9
16.2(a)	5.4.9
16.2(b)	5.4.9
16.3(a)(i)	5.4.9
16.3(a)(ii)	5.4.9
16.3(a)(iii)	5.4.9
16.3(b)(i)	5.4.9
16.3(b)(ii)	5.4.9
16.3(b)(iii)	5.4.9
16.3(b)(iv)	5.4.9
16.3(b)(v)	5.4.9
16.3(b)(vi)	5.4.9
16.3(b)(vii)	5.4.9
16.3(b)(viii)	5.4.9
16.3(b)(ix)	5.4.9
16.4(a)	5.4.9
16.4(b)	Regulatory Template 4.4

Response to Rules requirements

NER requirement and rule	Regulatory proposal section where addressed
6.3.1(c)(1)	Sections 1.1.3, 13, 14, 17.1 to 17.4 and 20
6.3.1(c)(1)	Sections 1.1.3, 17.3 and 20
6.3.1(c)(1)	Section 1.1.3
6.3.1(c)(2)	Section 1.1.4
6.5.6(a)	Sections 1.1.3, 6.1, 6.2, 6.12 and 6.12.1
6.5.6(b)(1)	Sections 1.1.3, 6.1, 6.11, and 17.1.7
6.5.6(b)(2)	Sections 1.1.3 and 6.11

NER requirement and rule	Regulatory proposal section where addressed
6.5.6(b)(3)	Sections 1.1.3, 6.1 and 6.11
6.5.7(a)	Sections 1.1.3, 5.2.12, 5.4.4,5.5.3, 5.6.4, 5.7.3, 5.8.3, and 5.9.3
6.5.7(b)(1)	Sections 1.1.3 and 5.2.10
6.5.7(b)(2)	Sections 1.1.3 and 5.2.10
6.5.7(b)(3)	Sections 1.1.3 and 5.1
6.5.7(b)(4)	Sections 1.1.3 and 5.2.11 and Regulatory Template 4.2
6.7.5(d)	Section 24
6.8.2(c)(1)(i)	Section 3.1
6.8.2(c)(1)(ii))	Section 3.2
6.8.2(c)(2)	Sections 1.1.1 and 1.1.3. See sections 4 to 17 generally.
6.8.2(c)(3)	Section 18.2
6.8.2(c)(3)	Section 18
6.8.2(c)(4)	Sections 19.5
6.8.2(c)(5)	Section 24
6.8.2(d)	Section 1.1.2
6.8.2(d)	Section 1.1.2
S6.1.1(1)	Sections 1.1.3 and 5
S6.1.1(1)	Sections 1.1.3, 5.3, 5.4.1, 5.5.1, 5.6.1, 5.7.1, 5.8.1, and 5.9.1
S6.1.1(1)	Sections 1.1.3, 5.2.2, 5.4.1, 5.5.1, 5.6.1, 5.7.1, 5.8.1, and 5.9.1, and Regulatory Template 2.1.
S6.1.1(2)	Sections 1.1.3, 5.4.5, 5.5.4, 5.6.5,5.7.4, 5.8.4, and 5.9.4
S6.1.1(3)	Section 1.1.3 and 4.1
S6.1.1(3)	Section 1.1.3 and 4.2
S6.1.1(4)	Section 1.1.3 and 5.2.1
S6.1.1(5)	Section 1.1.3, 5.2.1 and 26
S6.1.1(6)	Section 1.1.3 and 5.10
S6.1.1(7)	Section 1.1.3, 5.4.8, 5.5.5, 5.6.6, 5.7.6, 5.8.7, 5.9.7 and 5.10
S6.1.2(1)	Sections 1.1.3, 6.1 and 17.1.7
S6.1.2(1)	Section 6.1 and Regulatory Template 2.2.
S6.1.2(1)	Section 6.1
S6.1.2(2)	Section 6.9
S6.1.2(3)	Section 6.9
S6.1.2(3)	Section 6.9
S6.1.2(4)	Section 6.7
S6.1.2(5)	Section 6.4
S6.1.2(6)	Sections 6.4 and 26
S6.1.2(7)	Sections 6.8.2, 6.8.3 and 6.12.1
S6.1.2(8)	Section 6.14
S6.1.3(1)	Section 6.12.3.
S6.1.3(10)	Roll Forward Model
S6.1.3(10)	Post Tax Revenue Model
S6.1.3(11)	Section 16
S6.1.3(12)	Sections 13.5
S6.1.3(12)(iii)	Sections 13.4 and 13.5
S6.1.3(12)(iv)	Section 13
S6.1.3(12)(v)	Section 13
S6.1.3(13)	Section 2
S6.1.3(2)	Sections 12 and 18.2.2
S6.1.3(3)	Section 9.1
S6.1.3(4)	Section 10.1
S6.1.3(5)	Section 11
S6.1.3(6)	Sections 17 and 18
S6.1.3(6)(i)	Section 17
S6.1.3(6)(ii)	Section 17

NER requirement and rule	Regulatory proposal section where addressed
S6.1.3(6)(iii)	Sections 1.1.3 and 17
S6.1.3(7)	Section 14.3
S6.1.3(7)(i)	Section 14 and the Roll Forward Model
S6.1.3(7)(ii)	Sections 14 and 20
S6.1.3(7)(iii)	Section 14 and the Roll Forward Model
S6.1.3(8)	Section 15.2
S6.1.3(9)	Section 15
S6.2.1(b)	Roll Forward Model
S6.2.1(c)	Sections 14.2.1 and 14.2.2

30. ATTACHMENTS

This chapter sets out all Attachments to this Regulatory Proposal.

ID	Document name	RIN table reference	Regulatory Proposal reference	Confidential
C0001	Email of 21 Sept 2009 from Brent Cleeve(Powercor Australia) to L.Irlam (AER)	-	1	Yes
C0002	SKM, Accommodating Distribution Generation in the CitiPower Network, October 2009	-	5	No
C0004	AEMO, Terminal station demand forecasts 2009-10 to 2018-19	-	4	No
C0005	NIEIR, Electricity sales and customer number projections for CitiPower region to 2019, November 2009	-	4	Yes
C0006	NIEIR, Projections at Terminal Stations, October 2009	-	5	Yes
C0007	CitiPower, CIC documentation-Capital expenditure evaluation policy manual	none	5	Yes
C0008	CitiPower, CIC documentation-authorisation and payment of project expenditure and services manual	none	5	Yes
C0009	CitiPower, CIC documentation – Post investment review of financial planning analysis	none	5	Yes
C0010	CHED Services, IT Strategic Plan	6.4	5	Yes
C0012	Gartner, Review of Powercor/CitiPower IT Strategy, November 2009	none	5	Yes
C0013	CitiPower, Summary of Governance Framework	-	5	Yes
C0014	CHED Services, IT Disaster Recovery Policy	6.4	5	Yes
C0015	CHED Services, IT Software Management Policy	6.4	5	Yes
C0015	CHED Services, Software Version Management and Maintenance Agreements Policy	6.4	6.4	Yes
C0016	AECOM, Climate Change Impact Assessment on CitiPower for 2011-2015 EDPR, 30 September 2009	-	5	No
C0018	CitiPower and Powercor Australia – Capital Investment Committee (CIC) meeting minutes Monday 11 May 2009	-	5	Yes
C0019	EPA, Bunding Guideline 1992 Publication 347;	-	5	No
C0020	Electricity Supply Association of Australia (ESAA), Guidelines for Oil Containment in the Electricity Supply Industry	-	5	No
C0021	EPA, SEPP (Waters of Victoria) and (Groundwaters of Victoria) – these policies regulate the release of contaminants, including oil, in storm water drains	-	5	No
C0022	Electricity Safety (Management) Regulations 1999	-	5	No
C0023	CitiPower, Electricity Safety Management Scheme	-	5	No
C0025	CitiPower, Oil Containment Guidelines	-	5	No
C0026	AER, Interval Meter Reassignment Requirements, Final Decision, May 2009	-	5	No
C0027	CitiPower, Transport Policy Manual	-	5	Yes
C0028	CitiPower, Electricity Networks Network Augmentation Planning Policies and Guideline	-	5	Yes
C0029	CitiPower, Asset Management Framework	-	5	Yes
C0030	CitiPower, Network Protection and Control Communications Strategy 2009 – 2014	-	5	Yes
C0031	CitiPower, Bushfire Mitigation Strategy Plan 2009-10	-	5	Yes
C0032	CitiPower, Environment Improvement Plan (Noise)	-	5	Yes
C0033	CitiPower, Transformer and Switchgear Replacement Plan (Methodology and Key Process Steps)	-	5	Yes

ID	Document name	RIN table reference	Regulatory Proposal reference	Confidential
C0034	Powercor Network Services, CitiPower Pty Deliverability Plan 2011 to 2015	-	5	Yes
C0036	Price Waterhouse Coopers, AMI Leveraged projects. An assessment of the justifiable need for investment in additional AMI capabilities, October 2009	-	5	No
C0037	CitiPower Pty (CEPU) Workplace Agreement 2007	-	5	No
C0038	CitiPower Pty (ASU;APESMA, NUW) Workplace Agreement 2007	-	5	No
C0039	AEMC, Review of Energy Market Frameworks in light of Climate Change Policies, 30 September 2009	-	12	No
C0040	BIS Shrapnel, Wages Outlook for the Electricity – Distribution Sector in Victoria, August 2009	-	5	No
C0041	SKM, Victorian Distribution Network Service Providers annual material cost escalators 2010-15	-	5	No
C0042	PB, Review of CitiPower's policies, practices, procedures and governance arrangements, October 2009	-	5	Yes
C0043	CitiPower, Energy at risk and growth related capex	-	5	Yes
C0044	CitiPower 2008 -2010 Resources Agreement with PNS	-	5	Yes
C0045	CitiPower 2008 – 2010 Resources Agreement with CHED	-	5	Yes
C0046	CHED- CP Corporate Service Agreement	4.3 tables 1and2	5	Yes
C0047	PNS-CP Network Services Agreement	4.3 tables 1and2	5	Yes
C0048	Ernst and Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Construction and Maintenance Services, 30 November 2006	none	5	No
C0049	Ernst and Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Corporate Services, 20 November 2006.	None	5	No
C0050	Ernst and Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for Customer Services (Excluding Metering), 20 November 2006.	None	5	No
C0051	Ernst and Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services), 20 November 2006.	None	5	No
C0052	Ernst and Young, CitiPower Pty and Powercor Australia Limited Analysis of Transfer Prices for IT Services, 21 May 2009.	None	5	No
C0053	KPMG, The efficiencies of the CitiPower Service Model, September 2009	none	5	Yes
C0054	CitiPower Aerial Service Line Clearances, Safety Management Plan	6.4	5	Yes
C0055	CitiPower, Asbestos Management Manual 14-25-M0004	6.4	5	No
C0056	Watson Moss Growcott, Noise Control Report	-	5	No
C0058	Standard & Poors, credit rating requirements	none	6	No
C0059	CEG, Report on debt and equity raising costs	none	6	No
C0060	Debt raising cost model	none	6	Yes
C0062	Efficiency carryover model	none	6	Yes
C0063	Adjustments to regulatory Accounts	none	6	Yes
C0064	Post Tax Revenue Model	none	6	No
C0065	CHED Services, IT Asset Management Policy	6.4	6	Yes
C0065	CHED Services, IT Suppliers Policy	6.4	6.4	Yes
C0065	CHED Services, Servicing and Replacement Policy	6.4	6.4	Yes

ID	Document name	RIN table reference	Regulatory Proposal reference	Confidential
C0065	CHED Services, Green Purchasing Policy	6.4	6.4	Yes
C0065	CHED Services, Security of IT Assets (Hardware)	6.4	6.4	Yes
C0066	Aon, Self Insurance Risk Quantification – CitiPower Australia Ltd, October 2009	-	6	No
C0067	Aon – Insurance Cost Projections –CitiPower, October 2009	-	6	No
C0068	Vegetation Clearance Exemption – ESV Exemption ELS (ELC) Regulations 2005 – CitiPower	-	6	No
C0069	Standard and Poors'Refinancing And Liquidity Risks	-	6	No
C0070	AEMC, Review of National Framework for Electricity Distribution Network Planning and Expansion, 23 September 2009	-	6	No
C0071	CHED, Services Discretionary Risk Management Scheme Constitution	-	6	Yes
C0072	CHED, Discretionary Risk Management Scheme – Policy Framework	-	6	Yes
C0073	CitiPower, Purchasing and Procurement Policy	6.4	7	Yes
C0074	2008 Transmission Connection Planning Report (TCPR)	-	8	No
C0075	Powercor 2008 Distribution System Planning Report (DSPR)	-	5	No
C0076	Public Lighting Model	none	23	Yes
C0077	Roll Forward model	none	13	Yes
C0078	Letter proposing risk free rate and debt risk premium averaging period	none	15	No
C0079	Debt risk premium expert report	none	15	No
C0081	Equity raising cost model	none	15	No
C0082	Skeels report on gamma	none	15	No
C0085	Tax depreciation model	none	16	Yes
C0086	S Factor true up model	none	17	Yes
C0090	CHED-CP Metering and Field Services Agreement	4.3	22	Yes
C0091	PAL-CP Network Employee Sharing	4.3	22	Yes
C0092	KPMG, Report confirming the agreements are in line with the principles established by the board (multiple reports)	None	22	Yes
C0093	SKM, Scale Escalators Model review for CitiPower and Powercor, November 2009	-	22	Yes
C0094	SILK-CitiPower Corporate Communications Agreement	4.3	22	Yes
C0095	SILK-CitiPower Electrical Communications Agreement	4.3	22	Yes
C0097	Excluded Control Schedule	-	23	No
C0098	Statutory Accounts – Summary of Accounting Policies	6.4	5,6,17	Yes
C0099	CitiPower, Charter Network Project Committee (NPC)	6.4	6.4	Yes
C0100	CitiPower, Customer Contributions for Customer Initiated Augmentation Works (CIAW) Projects Guidelines	6.4	6.4	Yes
C0101	CitiPower, System Design Policy and Guidelines	6.4	6	Yes
C0102	Asset Management Plan –CitiPower HV Circuit Breakers	6.4	6.4	Yes
C0103	CitiPower, Asset Management Plan – CitiPower Underground Cables	6.4	6.4	Yes
C0104	CitiPower, Asset Management Plan – CitiPower Zone Substation Transformers Asset Management Plan	6.4	6.4	Yes
C0105	CitiPower, Asset Management Plan – CitiPower Poles	6.4	6.4	Yes
C0106	CitiPower, Transformer and Distribution Circuit Breaker Strategic Replacement Plan	6.4	6	Yes
C0107	CitiPower, Asset Management Plan – CitiPower Indoor HV Switchgear	6.4	6.4	Yes
C0108	CitiPower, Replacement Policy: Nilsen 3000 Amp type	6.4	6.4	Yes

ID	Document name	RIN table reference	Regulatory Proposal reference	Confidential
	AB LV ACB			
C0109	CitiPower, Non-Network Solutions Strategy Plan for CitiPower	6.4	8	Yes
C0110	CitiPower, Vegetation Management Plan 2009-2010	6.4	6.4	Yes
C0111	CitiPower, Asset Management Plan – CitiPower Pole Top Structures	6.4	6.4	Yes
C0113	Tabulated results 20090821.1.xls	-	15	Yes
C0114	Beggs and Skeels replication 2009082.sas	-	15	Yes
C0115	dataset_20090821.sas7bdat	-	15	Yes
C0116	market.sas7bdat	-	15	Yes
C0118	Ernst and Young, Metering Customer Service	-	22	Yes
C0119	Ernst and Young, Metering and Project Management Service	-	22	Yes
C0132	CitiPower, CIC Post Implementation Review of Approved Projects	6.4	6.4	Yes
C0133	Letter WMTS Transformer Rating October 2009		6	Yes
C0136	CHED Services, IT Security Management Policy	6.4	6.4	Yes
C0137	CHED Services, IT Disaster Recovery Strategy	6.4	6.4	Yes
C1000	AER, Regulatory Information Notice Under Division 4 of Part 3 of the National Electricity (Victoria) Law Appendix A, Regulatory Templates (Based on AER service classification)	6.4	-	Yes
C1100	AER, Regulatory Information Notice Under Division 4 of Part 3 of the National Electricity (Victoria) Law Appendix A, Regulatory Templates (Based on CitiPower service classification)	6.4	-	Yes
C0138	Objectives, criteria and factors by capital expenditure category	-	5	No
C0139	CitiPower, Negotiating Framework	-	24	No
C0140	CitiPower, Allocators used to populate RIN Regulatory Templates	1.2	1	Yes
C0141	ESCV, Electricity Distribution Price Review 2006-10 Final Decision Volume 2, Price Determination, October 2005	-	18	No
C0142	CitiPower, 2010 Annual Tariff Report		18	No
C0150	AER, Framework and approach paper for Victorian electricity distribution regulation CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011	3	1	No
C0144	AON, Self Insurance Risk Quantification Report, June 2007	-	22	No
C0151	ESCV, Electricity Industry Guideline No. 14, Provision of Services by Electricity Distributors	-	5	No
C0152	ESCV, Electricity Distribution Code	-	5	No
C0153	Electricity Distribution Licence	-	6	No
C0154	AER, Formal Decision on CitiPower's current approach to charge new customers capital contribution for upstream network augmentation and further consultation on what should be the fair and reasonable charging rates, July 2009	-	5	No
C0155	AER, Final Determination, Victorian advanced metering infrastructure review, 2009-11 AMI budget and charges application, October 2009	-	1	No
C0156	ESCV, Electricity Industry Guideline No. 3, Regulatory Information Requirements	-	1	No

ID	Document name	RIN table reference	Regulatory Proposal reference	Confidential
C0180	CitiPower, Proposed Cost Allocation Methodology	-	1	Yes
C0157	Electricity Safety (Installations) Regulations 1999	-	5	No
C0181	Australia Standards, Storage and handling of flammable and combustible liquids	-	5	No
C0158	Occupational Health and Safety (OHS) Regulations 2007	-	5	No
C0159	Environment Protection (Industrial Waste Resource) Regulations 2009	-	5	No
C0160	Electricity Safety (Network Asset) Regulations 1999	-	5	No
C0161	Electricity Safety (Management) Regulations 1999	-	5	No
C0162	Electricity Safety Act 1998	-	5	No
C0163	Electricity Industry Act 2000	-	5	No
C0164	Electrical Safety Amendment Act 2007	-	5	No
C0165	Energy and Resources Legislation Amendment Bill 2009	-	5	No
C0166	National Electricity (Victoria) Act 2005	-	5	No
C0167	Electricity Safety (Electric Line Clearance) Regulations 2005	-	5	No
C0168	Electricity Safety (Bushfire Mitigation) Regulations 2003	-	5	No
C0169	ESV, Regulatory impact Statement, Electricity Safety (Management) Regulations 2009, August 2009	-	5	No
C0170	ETSA Utilities, Regulatory Proposal 2010-2015, 1 July 2009	-	6	No
C0171	ElectraNet, ElectraNet Transmission Network revenue Proposal – Volume 1, 1 July 2008 to 30 June 2013	-	6	No
C0172	AER, Final Decision New South Wales distribution determination 2009-10 to 2013-14	-	12	No
C0173	AER, Electricity Distribution Network Service Provider Service Target Performance Incentive Scheme, May 2009	-	10	No
C0174	AER, Explanatory statement, Proposed amendment, Service target performance incentive scheme, September 2009	-	10	No
C0175	AER, Electricity distribution network service providers, Efficiency benefit sharing scheme, June 2008	-	9	No
C0176	AER, Demand management incentive scheme – Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011-15	-	11	No
C0178	AER, Energy Efficient Public Lighting Charges – Victoria Final Decision, February 2009	-	23	No
C0179	Public Lighting Code	-	23	No
C0182	Melbourne CBD Security of Supply Project Plan	-	5	No
C0183	PB, Weighted average remaining life of assets	6.2	5	No
C0184	Utilisation model	6.2	5	No
C0190	SKM, CitiPower Review of CBD Security of Supply and Planning Standards: Updated Final Report, 22 August 2006	-	5	No
C0191	NERA, Melbourne CBD Enhancement: Regulatory Test Analysis, CitiPower, 5 April 2007	-	5	No
C0192	ESC, Final Decision, CBD Security of Supply, February 2008.	-	5	No
C0193	CitiPower, Request for Proposals, RFP 001/06, Projected Distribution Network Limitations, Melbourne Central Business District Victoria, December 2006.	-	5	No

ID	Document name	RIN table reference	Regulatory Proposal reference	Confidential
C0186	SKM, Fault Level Mitigation Issues Paper: Embedded Generation in CitiPower Distribution System, November 2009	-	5	No
C0194	Value Advisor Associates, Market Risk premium 2011-15, October 2009	-	15	No
C0200	CEG, Update to June 2009 Report: Debt and Equity Raising Costs, 20 November 2009	-	15	No
C0201	Changes and Reasons for Changes to the Completed Regulatory Templates	-	1	Yes